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FUEL OPTIONS FOR ENHANCED HYDROCARBON RECOVERY

A Report

5-9142

MICROMEDIA

283p

Prepared by:

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November , 1985

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EXECUTIVE SUMMARY

1.0 Introduction

In 1979 Esso commenced the movement for recovery of in situ tar sand and heavy oil with the initial application for the Cold Lake steam injection oil recovery and heavy oil upgrader project. At that time the ERCB maintained a general policy of using coal rather than natural gas as energy for future thermal power generation. The Board did not relent and permit Esso to use natural gas rather than coal as primary offsite fuel until the offsite fuel demand projections had been reduced to less than 400 kilotonnes/annum. Now all projects smaller than Esso Cold Lake need not contend with the alternate fuelling problem and are free to pursue natural gas.

It is the object of this study to re-examine the capital and operating costs associated with alternative steam raising fuels to assess the current economics at anticipated scales of operation and at different producing locations within Alberta.

2.0 Enhanced Hydrocarbon Recovery Offsite Fuel Demand

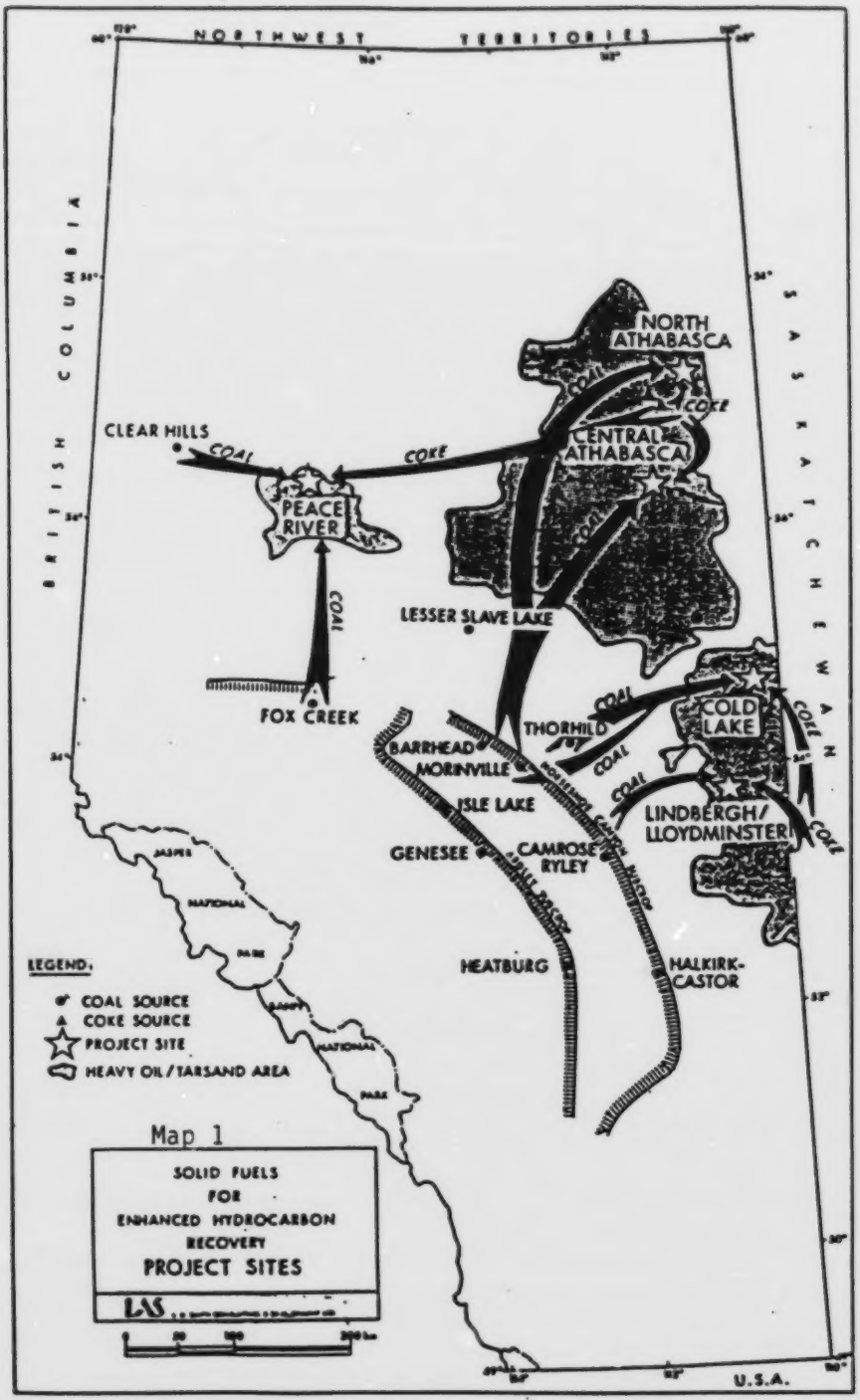
Canada contains nearly 50% of the world oil sand and heavy oil reserves. Primarily located in Alberta, these reserves are widely scattered in eastern and north central Alberta (see Map 1). The major deposits of interest occur at Peace River, Athabasca, Cold Lake and Lloydminster with the bulk of the reserves occurring in the Athabasca/Wabasca area, as indicated on Table 1.

Table 1
In Place Oil Reserves of Alberta

Area	Reserves ($10\ m^3$)
Athabasca/Wabasca	241
Cold Lake	33
Peace River	11
Buffalo Head Hills	1
Lloydminster	3
	289

Source: 1984 ERCB estimates.

The recovery potential of these deposits will ultimately be very low, but even at 10% to 20% recovery, the resource potential will be 30 to 60 billion m^3 of recoverable heavy oil/tarsand. The presently indentified recovery potential as delineated by active development projects is shown on Table 2. It is noted that the Cold Lake and Lindbergh/Lloydminster areas contain the bulk of the production potential.



Map 1

SOLID FUELS
FOR
ENHANCED HYDROCARBON
RECOVERY
PROJECT SITES

Table 2
Production Potential of Heavy Oil & Oil Sands Areas
Alberta In Situ Projects (m^3/d)

Area	No. of Companies	Production Level			
		Current	Additional Planned	Additional Possible	Total
Athabasca	3	160	1,640	5,600	7,400
Cold Lake	13	7,675	32,760	10,365	50,300
Lindbergh/Lloyd	5	600	10,700	6,400	17,700
Peace River	2	160	6,240	1,600	8,000
Total	23	8,595	51,340	23,965	83,900

Source: LAS estimate from discussions with producers.

Table 3 provides the total energy demand by fuel (which also represents the offsite fuel demand at most if not all projects). The data indicates the total energy requirements to be significant even for the natural gas industry.

Table 3
Fuel Demand for EOR Projects

Fuel Type	Annual Energy Demand		% of Present Annual Production	
	Minimum	Maximum	Minimum	Maximum
Natural Gas	240 petajoules	295 petajoules	9.5%	11.8%
Coal	10.5 megatonnes	17.3 megatonnes	67.0%	110.0%
Coke	6.3 megatonnes	10.4 megatonnes	460.0%	760.0%

Source: LAS estimate.

This study examines the economics of fuelling the steam production at two sites in Athabasca and at chosen localities at each of the other sites.

3.0 Fuel Supply and Pricing

In order to determine the most economical fuel used at each of the major heavy oil tarsand areas, the technical acceptability and the delivered fuel cost (including purchase, transport to site, offloading and storage) were examined at each demand site. In order to maximize each fuel's cost effectiveness, a number of logical sources for each fuel are selected. The fuels considered are:

Lease Crude - included at a cost of \$20/bbl ($\$125.80/m^3$) but cannot compete with natural gas.

Electricity - priced at \$0.04/kwh (current boiler technology is not adequate to meet steam specifications).

Natural Gas - priced at $2.51/GJ ($2.65/mcf), natural gas is the current fuel of choice, with adequate supply, convenience and proven technology. The negative aspects are high opportunity cost and regulatory uncertainty.

Petroleum Coke - petroleum coke is the residue left from the destructive distillation of crude petroleum. Available in Ft. McMurray and (possibly) Lloydminster, the present demand is less than supply but stockpiles are not adequte for more than a few major projects. Will provide an alternate fuel to coal in Fluidized Bed Combustion Steam Generators.

Coal - coal is very abundant in the Alberta Plains. The coal is sub-bituminous in rank and can be open pit mined using economical dragline technology. Typically, the coal has a heat content of about 18 to 20 MJ/Kg and a low sulphur content of 0.3% to 0.5%. The active mines produced 18.2 megatonnes in 1984 and sold nearly all production to local power plants. The mine site cost of the energy from this coal is about $0.60/GJ.

The price of the mined coal is estimated to be $12.35/tonne at a strip ratio of 7 bank cubic metres/tonne raw coal and the price increases or decreases with corresponding increases or decreases in the strip ratio of the coal deposit. Economic studies indicate that for any potential demand site, several coal deposits will be able to compete for supply of fuel.

4.0 Fuel Transportation

Natural Gas

The study assumes that the base purchase price of natural gas includes delivery to the lease boundary.

Bulk Materials Transportation

Three methods of transportation of coal are considered: trucking, rail and slurry pipeline. Coke would only be moved by rail or by truck at anticipated supply quantities.

Truck Transport - Truck transport costs for tonnages of less than 0.5 megatonnes/year cost about $0.06 to $0.063/tonne-km. Trucking logistics preclude use of trucking for tonnages greater than 0.5 megatonnes/year.

Rail Transport - Rail haulage, by car lot for tonnages less than 0.5 megatonnes/year, and unit trains for rates over 0.5 megatonnes/year include required price modifications to cover the upgrading of some rail lines and new rail additions to some demand sites and specific coal deposits. The summarized rates used are given on Table 4.

Table 4
Rail Rates
Solid Fuels

Mode	Annual Solid Fuel Demand (Kilotonnes)	Lindbergh & Peace River ($/tonne-km)	Cold Lake & Athabasca ($/tonne-km)
Car lot	100	0.0607	0.0657
	200	0.0515	0.0565
	300	0.0458	0.0508
	400	0.0423	0.0473
	500	0.0402	0.0452
Unit Train	500	0.0310	0.0360
	600	0.0289	0.0339
	800	0.0260	0.0310
	1000	0.0242	0.0292
	1500	0.0221	0.0271

Note: (1) Based on current 1985/86 rates + 8%.
(2) Upgrading costs of $0.005/tonne-km assumed for Cold Lake and Athabasca.
(3) LAS estimate based on industry data.

Slurry Pipeline Transport - Slurry pipeline transport of coal is technically practical and was examined by Singleton Associated Engineering Ltd. for this project. The studies examine direct distance from coal source to demand centre plus 10%, include 70 km of fresh water line, and are costed at various tonnages. The resultant rates shown on Table 5 are considered realistic for coal haulage rates.

Table 5
Slurry Pipeline Rates

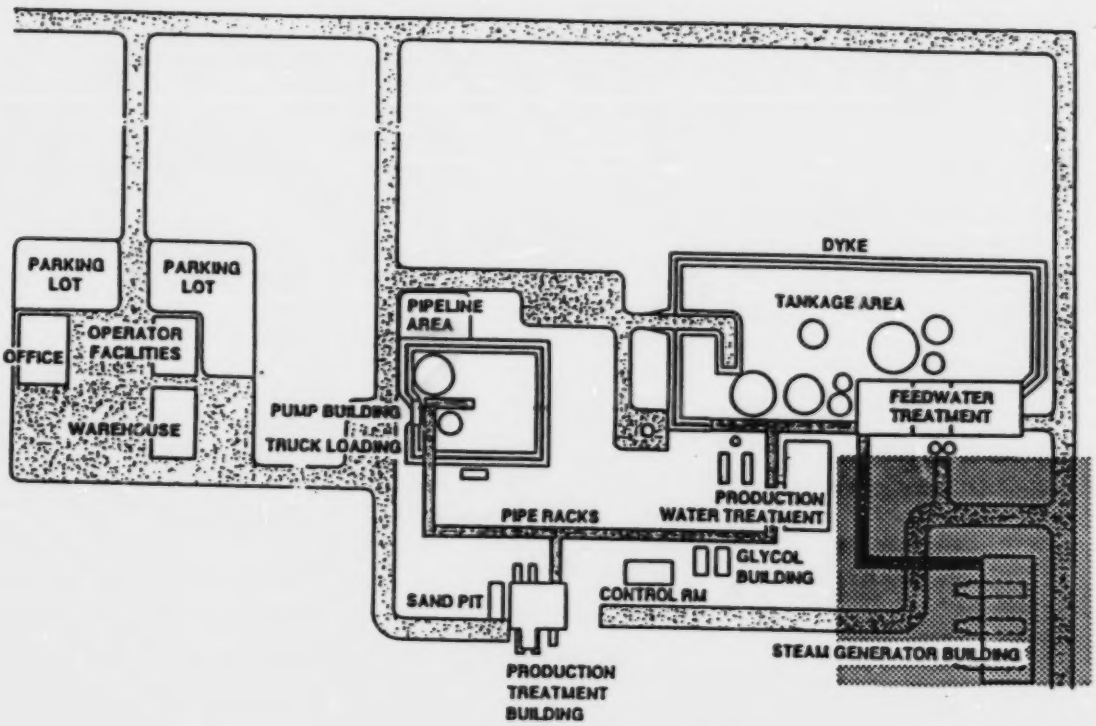
Annual Throughput (kilotonnes/yr)	Cost ($/tonne-km)
360-450	0.1197
470-600	0.0857
720-900	0.0616
950-1200	0.0493

Source: Singleton Associated Engineering Ltd.

5.0 Steam Raising Technology for EOR

This study includes the burning technologies that are considered practical for each fuel under current technology. The steam specifications that are assumed are for about 12,000 kpa at 80% quality wet steam. Generally we assumed use of 65% produced water/35% fresh water. The equipment included in the study is indicated in Figure 1.

Figure 1
Steam Generation Equipment Included In Study



Gas Fired Steam Generators

The typical gas fired steam generator assumed for this study are the 190 GJ/hr once-through forced air gas fired steam generator. The capital and operating costs assumed for varying numbers of these units are shown on Table 6.

Table 6
Capital and Operating Costs
Gas Fired Generators

Number	Installed Price ($x1000)	Operating Cost as % Of Capital
1	3,900	17.5
2	7,100	16.2
4	12,850	15.0
5	15,600	14.7
10	28,250	13.8

Source: LAS estimate.

This study assumes that annual operating costs are a trended curve of the above percentages of the installed capital cost.

Fluidized Bed Combustion (FBC)

FBC technology can use a variety of fuels including coal, petroleum coke, lease crude and natural gas. This study assumes the ideal FBC unit size is 530 GJ/hr. Capital and operating costs are calculated as shown on Table 7.

Table 7
FBC Capital and Operating Costs

No. of Units	Installed Price ($x1000)	Operating Cost as % of Capital
1	38,490	9.9
2	61,240	10.2
4	97,440	10.5

Source: LAS estimate.

This study assumes annual operating costs are 10.25% of the installed capital cost.

Pulverized Coal Fired Units (PCF)

PCF technology was studied in detail by Esso in 1979. They concluded that technology required use of 55% fresh water superheated to about 300° F and then mixed with 45% produced water in a de-superheater. Additional technological development is

required. Capital and operating costs are calculated for 530 GJ/hr sized units and shown on Table 8. This study assumes that annual operating costs are 8.0% of the installed capital costs.

Table 8
PCF Capital and Operating Costs

No. of Units	Capital Cost ($x1000)	Operating Cost as % of Capital Cost
1	42,200	7.9
2	67,210	8.0
4	106,940	8.1

Source: LAS estimate

Other technologies such as PCF once-through generators, coal water mixtures and coal oil mixtures are briefly reviewed.

6.0 Regulatory and Environmental Issues

The environmental and regulatory problems that are considered for each fuel type include all governing pollution and socio-environmental aspects.

Coal - The environmental and regulatory problems that are included in the costing are: mining, transportation, coal unloading and storage, SO_x/NO_x emissions, particulates, ash disposal, labor force effects, and ERCB views on coal usage.

Coke - The use of limestone to eliminate the SO_x/No_x emissions is included in the FBC operating costs.

Natural Gas - This product is clean, safe and environmentally acceptable.

The order of fuel choice (first to last), when considered with respect to the regulatory and environmental issues is:

Natural Gas
Residual Oil
Coke
Coal

7.0 Comparative Economics

Questions concerning the economic viability of specific in-situ steam projects are outside the scope of this study. This study focuses exclusively upon the improvement (or deterioration) in project economics realized by using fuels other than natural gas for steam raising. That is, natural gas provides the "zero" of reference for the economics of the alternative fuels. These economics are developed on a "before income tax" basis which biases any comparison in favor of the least capital intensive alternative (i.e. natural gas). In addition, the cost of steam

generated by alternative fuels, using utility product costing principles (the "cost of service" approach), provides a very conservative measure of relative economic attractiveness when compared with discounted cash flow (DCF) measures of profitability derived from differences in steam generation related cash flows (alternative fuel less natural gas cash flows). If the alternative fuels can provide attractive economics under these severe conditions, more detailed analyses should yield improved economics. That is, the economics of this study are intended to define a lower bound to the more detailed economics.

Because of the higher capital and operating cost associated with solid fuels versus fluid fuels, economies of scale are important. For a lower priced fuel (i.e. lower commodity value), there is always some scale of operation that will permit equal economics with a higher priced fuel of lower associated capital and operating costs. That scale of operation at which equal economics occurs is herein called the "cross-over point". At production levels below the cross-over point, the economics of the alternative fuel are increasingly unfavorable. Above the cross-over point, the economics are increasingly favorable. Thus, the cross-over point is an economic "breakeven" level of operation. Within the base case assumptions, it is found that at each demand location assumed for study there is some minimum volume of fuel demand at which coal or petroleum coke can provide equal or better economics than natural gas.

Both coal and petroleum coke can be delivered at significantly lower commodity costs than natural gas to steam generating facilities. This lower commodity cost is offset by higher capital and operations costs associated with the handling, transportation, combustion, and cleanup of solid fuels. On a utility unit product costing basis, the crude production levels at which coal and coke provide steam of equal cost to that generated with natural gas are summarized in Table 9.

Table 9
Steam Cost Cross-Over Points

	Coal			Coke		
	Production Level (m^3/d)	Fuel Consumed (k t/yr)	IRR	Production Level (m^3/d)	Fuel Consumed (k t/yr)	IRR
Lindbergh	3,902	730	21.2%	2,765	317	20.6%
Cold Lake	5,520	824	21.5%	4,800	446	19.6%
Peace River	4,800	1,104	20.4%	>6,400	---	---
C Athabasca	4,800	1,194	20.5%	1,733	239	20.6%
N. Athabasca	6,344	1,578	20.5%	1,673	231	20.5%

Note: (1) Points of steam-cost equivalence with natural gas on a utility cost of steam basis.
(2) Internal rate of return (IRR) on incremental investment in solid-fuel steam generation equipment.

At Lindbergh, this crude production level corresponds to 730 kilotonnes of coal consumed per annum. On a discounted cash flow (DCF) basis, a "real" 10% internal rate of return (IRR) on the use of coal could be realized at only 400 kilotonnes of coal consumed per annum. This real rate of return is on the incremental capital investment offset by net operating cost savings (including fuel cost savings). Similar results are obtained for the other production areas (see Table 10).

Table 10
10% IRR Cross-Over Points

	Coal		Coke	
	Production Level (m^3/d)	Fuel Consumed (k t/yr)	Production Level (m^3/d)	Fuel Consumed (k t/yr)
Lindbergh	2,140	400	1,113	128
Cold Lake	3,274	532	2,120	197
Peace River	3,287	760	3,760	415
Central Athabasca	3,456	860	592	82
Northern Athabasca	3,578	890	561	77

Note: (1) Points at which incremental cash flows of solid-fuel steam generation yield at 10% IRR relative to natural gas steam generation.
(2) Fuel consumed is estimated according to the heat-value at source.

Clearly, the DCF basis of comparative economics suggests closer competition between natural gas and the alternate fuels than the accounting cost-of-steam comparisons. There is almost a 10% IRR "margin of safety" in the utility product costing approach. Even on a utility costing basis, the "break-even" volumes of crude production are well below planned levels at each producing region. Operator cooperation, on at least transportation and stockpiling, between projects within a producing region, could provide significant solid fuel cost savings over natural gas and free natural gas for sales at higher other market prices.

Table 11 summarizes the differential DCF economics of coal versus natural gas at each of the study areas. These economics illustrate both the influence of distance-of-haul and the progressive improvement in economics with increasing consumption and/or scale of operation. It should be emphasized that all rates of return are expressed in real terms. Therefore, an average inflation rate estimate must be added to the IRR's before comparisons with prevailing interest rates. The IRR (in this study) is an answer to the question, "How much real interest can the project afford to pay for the additional capital costs of the fuel alternative to natural gas and still break even?" With current "real" interest rates (ex inflation) at about 7%, the comparison becomes favorable for all five areas at about $3200 m^3/d$ (20,000 BOPD). On an after tax basis, the economics would become

better at lower production levels.

Table 11
Coal DCF Economics
Summary by Location
Internal Rates of Return*
(%)

Prodn. Level (m^3/d)	Lindbergh	Cold Lake	Peace River	Central Athabasca	Northern Athabasca
800	0.2	-11.0	-9.2	-8.4	-
1,600	7.1	-1.6	-0.6	0.3	-
2,400	11.4	2.6	3.8	4.8	3.1
3,200	17.3	9.6	9.4	8.0	8.3
4,800	26.1	18.3	20.4	20.5	15.5
6,400	33.4	23.5	27.7	28.2	20.7

* Derived from steam generation cash flow differences: coal-fired less gas-fired.

Table 12 provides the DCF results obtained for coke. As discussed earlier, steam quality coke may suffer supply limitations that would preclude the attainment of the indicated economics. Nevertheless, both the Lindbergh and the Athabasca areas show such positive economics that serious consideration of coke fueled steam generation is warranted in those areas. Coke is also competitive with coal at Cold Lake, assuming a Lloydminster source. Coke at Peace River suffers from the long distances assumed for haulage because no direct road or rail link between Peace River and Athabasca was assumed.

Table 12
Coke DCF Economics
Summary by Location
Internal Rates of Return*
(%)

Prodn. Level (m^3/d)	Lindbergh	Cold Lake	Peace River	Central Athabasca	Northern Athabasca
800	7.3	0.8	-	12.0	12.3
1,600	14.2	7.4	-	19.7	20.0
2,400	18.9	11.4	-12.7	25.2	25.6
3,200	22.7	14.6	-6.4	29.8	30.2
4,800	28.9	19.6	11.9	37.5	37.9
6,400	33.1	23.8	18.0	43.9	44.5

* Derived from steam generation cash flow differences: coke-fired less gas-fired.

The sensitivities of these economic results to changes in capital costs, natural gas prices, and steam/oil ratios are also measured in this study at Lindbergh (see Figures 2 and 3). The sensitivities are quantitatively similar for both coal and coke in that the order of sensitivities is:

Natural Gas Price > Capital Cost > Steam/Oil Ratio

What is surprising within these relationships is the relative insensitivity of the economics to steam/oil ratio (i.e. steam demand). Conversely, the economics are very sensitive to gas prices and capital costs.

The graphs of cross-over points at Lindbergh, as a function of changes in the major variables from the base case values, are shown in Figures 2 and 3. In these graphs, all curves intersect at the base case. The curves or function lines illustrate the sensitivity of project economics to change in value of the critical project variables. For coal, as indicated in both Table 9 and Figure 2, the base case cross-over or steam cost equivalence production level is $3902 m^3/d$. A decrease of 10% in the capital cost of the coal-fueled steam generator facilities reduces the cross-over point to $3090 m^3/d$ for a drop of $812 m^3/d$ per 10% of capital cost change. Correspondingly for coke, a 10% reduction in capital cost yields a drop in cross-over point, at Lindbergh, from $2765 m^3/d$ to $1946 m^3/d$ for $819 m^3/d$ per 10% of capital cost change (assuming the availability of coke from Lloydminster by 1990).

The graphs of DCF IRR sensitivities at Lindbergh, at a production level of $3200 m^3/d$ (20,000 BOPD) are shown in Figures 4 and 5. Again, all lines intersect at the base case values. It is interesting to note that the IRR's are almost linear functions of natural gas price and steam/oil ratios while declining exponentially with increases in alternate fuel steam generation capital costs. The slopes (sensitivities of both the DCF IRR's and cross-over points are summarized in Table 13.

Table 13
Economic Parameter Curve Slopes
Lindbergh

Project Variable	Cross-Over Point (m^3/d/10% change)*		DCF IRR (%/10% change)*	
	Coal	Coke	Coal	Coke
Natural Gas Price	-1040	-1200	4.8%	5.5%
Capital Cost	840	930	-3.85%	-5.1%
Steam/Oil Ratio	- 330	- 300	1.8%	1.4%

* **Note:** Change in economic parameter per 10% change (-5% to + 5%) in variable value from base case value.

Figure 2

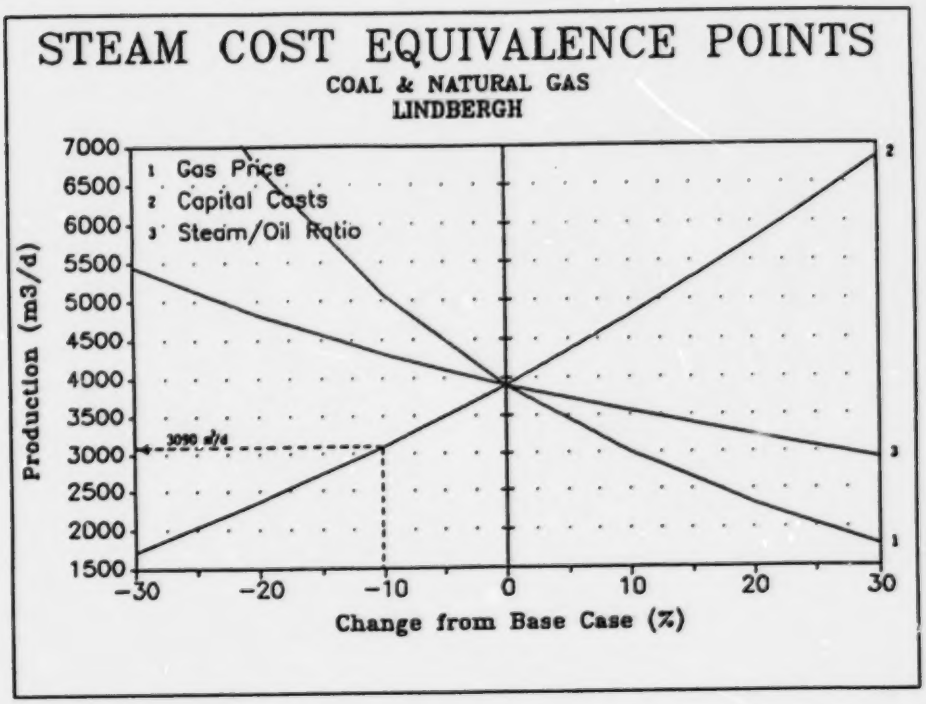


Figure 3

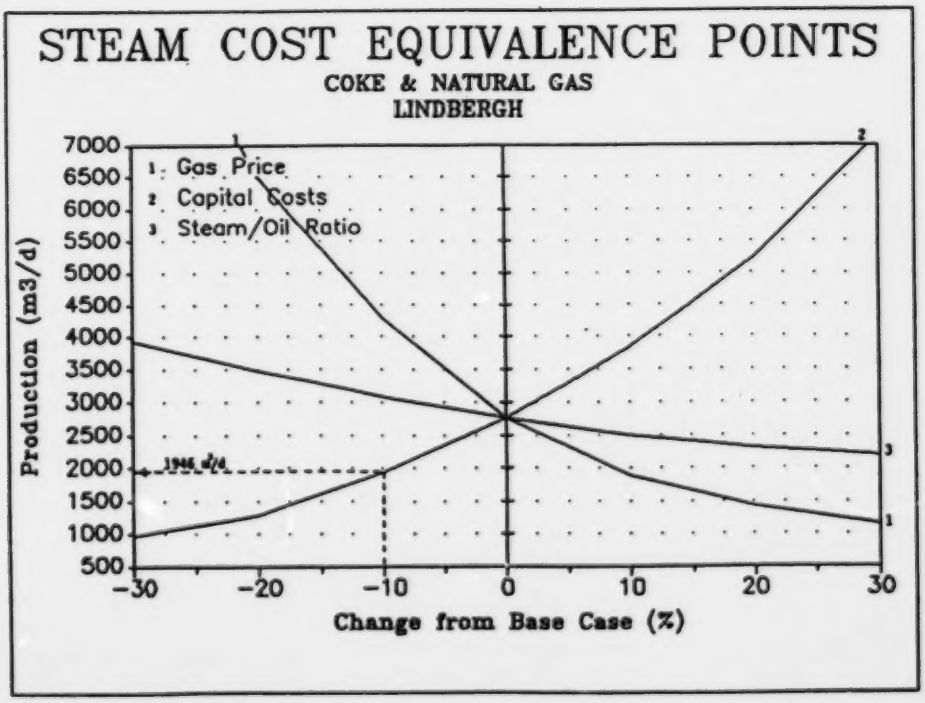


Figure 4

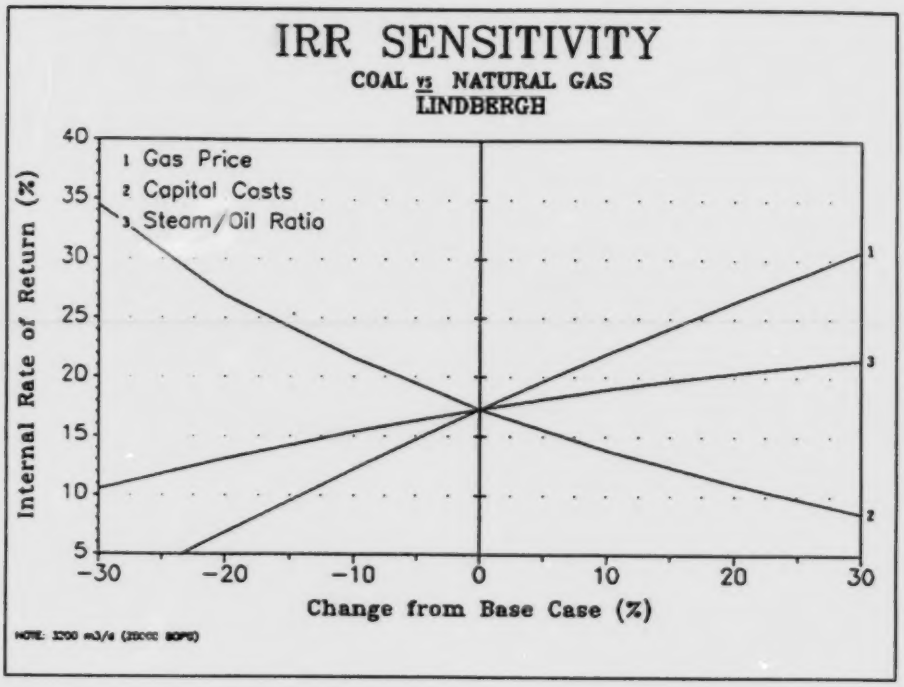
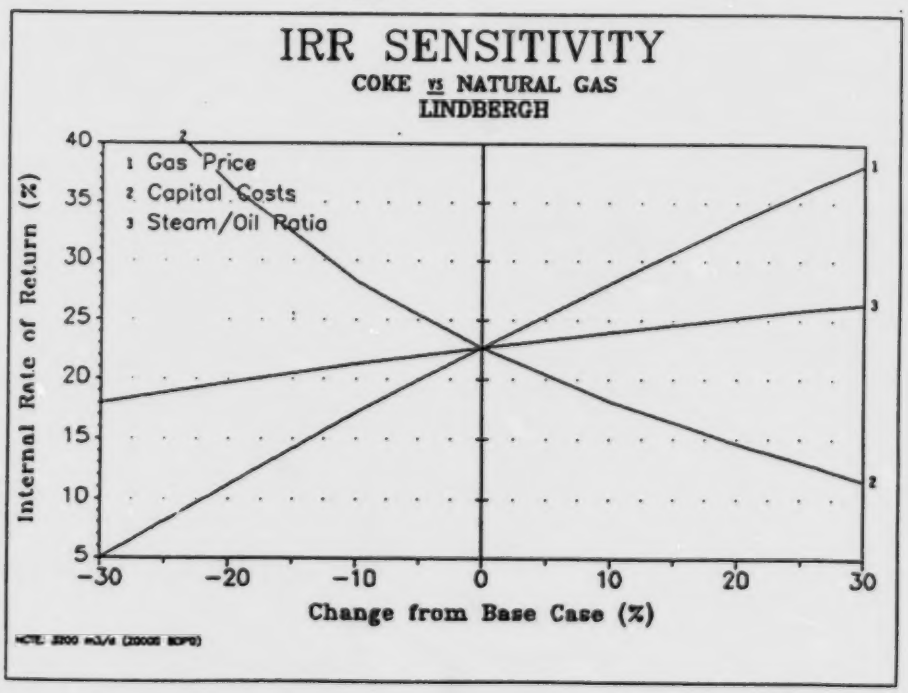


Figure 5



The general similarity in slopes between coal and coke is consistent with the common combustion technology assumed in the base cases. Coke economics are slightly more sensitive to gas price and capital cost than coal but are less sensitive to steam/oil ratio.

8.0 Conclusions

1. Fuel Demand

The ultimate projected fuel demand for enhanced hydrocarabon recovery projects in each of the major tarsand areas exceeds the threshhold at which coal and coke can become economically competitive with natural gas. Operator cooperation and coordination betweem adjoining or nearby projects can optimize the solid fuel economics even more and increase the "effective" scale of combined projects. Only natural gas has significant market alternatives for volumes not consumed for steam raising.

2. Fuel Supply

Proven reserves of natural gas are adequate to supply the requirements of current and anticipated domestic and export natural gas markets, including the thermally enhanced hydrocarbon recovery projects for at least 25 years. The proven reserves of Alberta plains sub-bituminous coal are a very under-utilized resource. The surface mineable reserves are more than adequate to supply all current and future demands beyond 25 years. The petroleum coke supply is constrained to the excess production (currently without a market) at the oilsands plants and the planned heavy oil upgrading facilities. Because coke could be supplemented by coal, this is not a serious limitation. Therefore, the supply of natural gas, coal, or coke is not a limiting factor in fuel selection.

3. Fuel Prices

The large range of market options for natural gas will likely maintain the present high opportunity cost relative to the solid fuels. The delivered cost of coal from several sources at each demand site is competitively close such that competition among producers will maintain a narrow price spread. Competition between coal and coke at FBC facilities will tend to restrain the price of petroleum coke to nearly the current quoted prices. Accordingly, competition within the steam generation fuels market will moderate solid fuel prices but natural gas prices (not determined by this market) are unlikely to fall below the relative values assumed for this study.

4. Fuel Transportation

Transportation costs dominate the delivered coal price and could have a major impact on the delivered coke price. For coal,

depending upon the volume and distance of haul, transportation accounts for 13% to 20% of the cost of delivered steam. The transport of petroleum coke accounts for about 4% to 8% of the corresponding cost of steam, assuming short hauls.

Pipeline transport of coal is technically and economically feasible to Peace River, Lindbergh and Central Athabasca at tonnages exceeding 900 megatonnes/year. As the in-situ steam projects increase in size and number, the potential for solid fuel substitution of natural gas will increase due to the reduction of transport rates caused by increases in volume of solid fuel transported.

5. Steam Generation Facilities

Solid fuels require more costly steam generation facilities than natural gas, and for these solid fuel technologies more engineering emphasis is required for steam distribution to compensate for greater centralization of the steam generation facilities. At present there is sufficient world wide experience in solid fuel firing technology to warrant serious consideration of solid fuel steam generation in Alberta oilfields where the scale of field operations are consistent with steam generation economies of scale.

Additional R&D work is required to obtain operating experience in Alberta for:

- FBC applications in Alberta oilfields,
- Pulverized Coal Firing of the once-through forced air type 190 GJ/hr steam generator,
- oilfield applications of the PCF boilers, and
- application of coal-water mixtures as fuel for the 190 GJ/hr steam generator.

6. Comparative Economics

The comparative economics of petroleum coke, as a steam generating fuel, are very good in those areas near an existing or potential source of supply. Coke using FBC technology yields comparative economics that exceed coal in all areas other than Peace River (which is remote from a coke supply). Therefore, the a major determinant of acceptability of coke is availability of supply at competitive prices (based upon heat and sulphur content).

Coal demonstrates acceptable DCF economics relative to natural gas at and above 2400 m^3/d (15,000 BOPD) at Lindbergh and at and above 3200 m^3/d (20,000 BOPD) at the other four areas. Coal economics are not circumscribed by questions of supply.

The major uncertainties and risks within the economics are associated with:

a) natural gas prices relative to solid fuel prices,
b) capital costs of solid fuel steam generators, and
c) fuel demand levels as partially determined through steam/oil ratios.

Of these, only capital costs are controllable to any degree. The large sensitivity of the economics to solid fuels capital cost suggests that any technological efforts made to reduce the costs and increase the flexibility of implementation of solid fuel steam generators would be well rewarded in improved overall project economics.

1.0 INTRODUCTION

The province of Alberta is in the enviable position of having many energy choices. There has been extensive public and private debate as to which source of energy is most appropriate for different applications. The Alberta Energy Resources Conservation Board (the Board) has stated that

> "....alternative fuels should be evaluated on the basis of energy utilization and efficiency, environmental impact, effect on project economics and optimum utilization of Alberta's energy resources." (ERCB 79-E.p.75)

In 1974 and 1975, the Board issued ERCB Reports 74-X and 75-H which stated the Board's general policy on the use of fuels at oil sands projects. One of these policy objectives was that such projects should be self-sufficient in energy (a supply of natural gas and an electrical power interconnection should be required for start-up and emergency purposes only).

In the earlier ERCB Report 73-C, the Board's analysis of the comparative costs and benefits to the Province of using coal or natural gas as thermal electric plant fuel concluded that coal provided

i) lower cost electricity throughout the forecast period and
ii) much greater overall benefits to the Province.

The use of coal in electric power plants was seen to permit the development of the sub-bituminous coal industry without detracting from the continued development of the gas industry. Subsequent to the report, the government of Alberta adopted the general policy that coal rather than natural gas should be the energy used for future thermal power generation.

In 1977, Esso Resources Canada Limited (Esso) made application to the Board to develop a project at Cold Lake which was to recover 22,300 m^3/d (140,000 BOPD) of synthetic crude oil. Simultaneously, Esso applied for an industrial development permit for the use of 2.3 million tonnes per annum of coal as the make-up fuel for the project. After the

hearing of this application, Esso submitted an amended application for the use of natural gas as a preferred make-up fuel. ERCB Report 79-E, October 1979, documents the Board's decision and states,

> "....the Board believes that the coal fuel case provides the greatest benefit to Alberta. This conclusion parallels that reached with respect to using coal at thermal power plants in the Province." 79-E,p76

Despite the Board's 1979 decision, natural gas remains a fuel of engineering convenience, flexibility, familiarity, local availability and, therefore, is the preferred fuel by most oil field personnel. Later debates concerning alternative fuels for oil field applications revolved around expected prices and whether price differentials were sufficient to overcome the capital and operating cost disadvantages of the alternative fuels.

After finding that make-up fuel requirements were less than submitted in earlier applications, Esso applied again in 1980 to use natural gas as the primary make-up fuel for the Cold Lake Project. In February 1981, the Board Published (ERCB) Decision 81-C which states:

> "Upon reviewing the Applicant's economic evidence, the Board accepts Esso's position that gas has become relatively more favourable than coal at the projected coal throughput volumes. The lower coal make-up fuel requirement has reduced the magnitude of future fuel cost savings to the point where the higher estimated coal-related investment may not be justified despite forecast real increases in gas prices."
> (ERCB 81-C, p 26)

and

> "In ERCB Report 79-E the Board expressed the view that natural gas was a premium hydrocarbon resource which should not normally be used for steam generation purposes. The Board believes this general policy should be flexible enough to provide for exceptions if circumstances warrant it. Some of the more important factors which might influence a decision include consideration of environmental effects, economic impact, the proximity of the project to coal and gas reserves, and the size of the project in terms of energy requirements.

> In summary, the Board does not believe the general provincial policy of restricting the use of natural gas for steam raising should dictate a denial of the subject application. A comparison of alternative fuels should be made on the basis of their relative merits in the particular circumstances of the Cold Lake Project." (ERCB 81-C, p27-28)

Subsequent to this later decision, all projects of a lesser size than the Esso Cold lake Project (as approved) automatically receive approval for the use of natural gas as a make-up fuel for steam raising. However, since that decision, both domestic and export markets for natural gas have improved and continue to offer significant growth opportunities. The opportunity costs of burning natural gas for steam raising have increased. In spite of these factors, the costs and benefits to oilfield operators and the Province of using alternative fuels for steam raising are not, as yet, readily apparent.

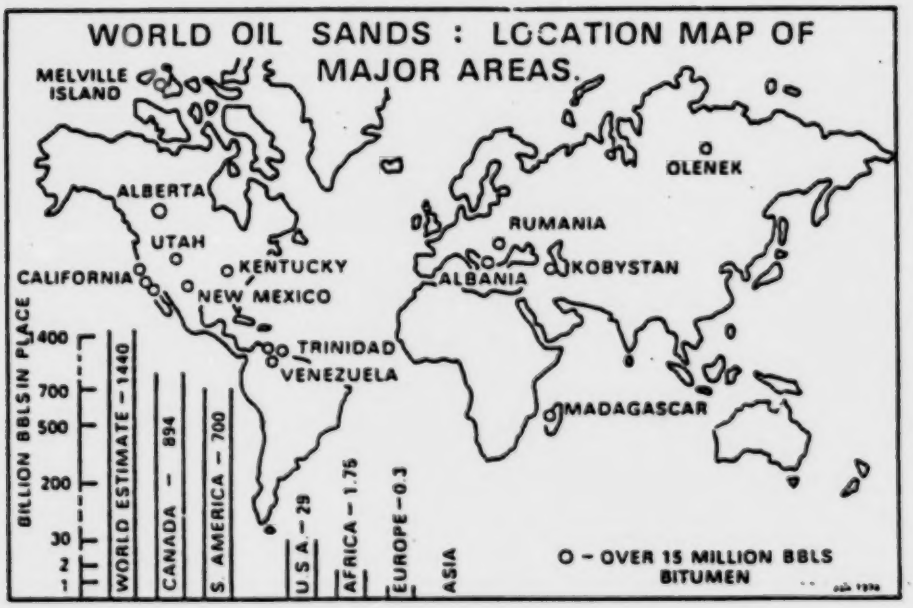
It is the objective of this study to re-examine the capital and operating costs associated with alternative steam raising fuels to assess the current economics at anticipated scales of operation and at different producing locations within Alberta.

2.0 ENHANCED HYDROCARBON RECOVERY OFFSITE FUEL DEMAND

2.1 Introduction

Heavy oil and bituminous sand deposits are known to occur on all continents of the world except Australia (see map) and constitute a major future source of energy. World estimates in the order of 1500 billion barrels in place have been determined (excluding Asian deposits), with the vast majority located in Alberta and Venezuela. The significance of these reserves can only be fully appreciated when one compares the above reserve total with the known reserves figure for world conventional oil of 698.7 billion barrels (O&G Jour., 12/31/84).

Fig. 2.1



2.1.1 Definitions

Because of the unique nature of heavy oil and bituminous sand deposits and their intergradational nature, the following definitions have been used in this study:

Heavy Oil: A naturally occurring complex liquid hydrocarbon which has a high C/H ratio resulting in densities between 900 and 970 kg/m^3 at 15° C, and that in its naturally occurring state is producible at a commercial rate by conventional methods.

Bituminous Sands: The oil sands that occur within townships 84 to 104 inclusive in ranges 4 to 19 inclusive, west of the 4th meridian and occurring in the McMurray Formation, the stratigraphic formation lying above the Upper Devonian carbonate sediments and below the Clearwater Formation (The Mines and Minerals Act 2.(1)2.).

Crude Bitumen: A naturally occurring viscous mixture, mainly of hydrocarbons heavier than pentane, that may contain sulphur compounds, and that in its naturally occurring state is not recoverable at a commercial rate through a well (The Oil and Gas Conservation Act 1.(1)10.).

Oil Sands: i) sands and other rock materials containing crude bitumen

ii) the crude bitumen contained in those sands and other rock materials, and

iii) any other material substances in association with that crude bitumen or those sands and other rock materials, but does not include petroleum or natural gas that in its naturally occurring state is recoverable through a well by conventional methods (The Mines and Minerals Act 2.(1)20.).

2.1.2 Distribution of Total Reserves

As can be seen on Table 2.1, Canadian oil sand and heavy oil reserves constitute 47% of world reserves. These reserves are primarily located in Alberta and have been assigned to four specific areas which include, from NW to SE, the Peace River, Athabasca-Wabasca, Cold Lake and Lloydminster deposits. The largest of these is the Athabasca-Wabasca deposit which accounts for over 83% of the nearly 290.2 x $10^9 m^3$ in place reserves (see Table 2.2).

Table 2.1

World Oil Sands Reserves
(Proven & Probable)

Country	Reserves	
Canada	$363.360 \times 10^9 m^3$	2.28510×10^{12} bbls.
S. America	$317.965 \times 10^9 m^3$	1.99970×10^{12} bbls.
U.S.S.R.	$95.390 \times 10^9 m^3$	0.59990×10^{12} bbls.
U.S.A.	$3.798 \times 10^9 m^3$	0.02390×10^{12} bbls.
Trinadad	$0.318 \times 10^9 m^3$	0.00200×10^{12} bbls.
Madagascar	$0.278 \times 10^9 m^3$	0.00170×10^{12} bbls.
Europe	$0.063 \times 10^9 m^3$	0.00040×10^{12} bbls.
Peru	$0.010 \times 10^9 m^3$	0.00007×10^{12} bbls.
Total	$781.182 \times 10^9 m^3$	4.9120×10^{12} bbls.

(Source: CIMM, 1977)

A breakdown of in-place oil can be seen from Table 3.2 which was compiled from data reported by the ERCB (84-18) and the NEB (Heavy Oil Update, 11/83).

Table 2.2

In-Place Oil Reserves of Alberta

Area	No of Reservoir Zones	IVIP	°API Gravity ERCB/NEB	Handbook Energy Tech. & Econ.
Athabasca/Wabasca	5	$241.53 \times 10^9 m^3$	4-10 (gen.8)	8-13
Cold Lake	4	33.30	4-14 (gen.10-14)	10-12
Peace River	2	11.40	4-10 (gen.8)	8-9
Buffalo Head Hills	2	0.92	4-10 (gen.8)	N/A
Lloydminster*	9	3.30	4-20 (gen.15-17)	N/A

* Heavy oil deposit rather than bituminous sand - spans Alberta/Saskatchewan boundary. The initial crude volume in-place for the Lloydminster deposit has been broken down by province by both the NEB and the respective provincial regulatory agencies. These studies indicate that the majority of the reserves of this area are located in Saskatchewan ($2.3 \times 10^9 m^3$) rather than Alberta ($0.946 \times 10^9 m^3$).

2.1.3 Trends and General Constraints

There are several variables and constraints which stand out when reviewing the heavy oil and bituminous sand deposits in

Alberta. Included in these are:

i) oil gravity
ii) number of reservoirs
iii) thickness of reservoirs
iv) oil saturation
v) presence of basal water within the reservoir
vi) accessibility, and
vii) technology

Oil gravity (°API) is inversely related to the fluid density of liquid hydrocarbons and ranges from about 4° to 20° for entities classified as heavy for the purpose of this study (greater than 900 kg/m^3 density). Table 3.2 indicates a trend toward higher gravity (less dense) hydrocarbons to the south and east. The existence of this trend is supported by the current production activity in the Cold Lake and Lloydminster regions.

The number and thickness of prospective reservoirs reflect little more than the location of the ancient shoreline and delta complex to the site of post-depositional hydrocarbon entrapment. Except for the Grosmont carbonate reservoirs which occur adjacent to and in contact with the Cretaceous sands of the Western Athabasca deposit, the oil sands are restricted to clastic reservoir rocks of the Lower Cretaceous Mannville Group. The number of potential reservoirs increases generally in an eastward and southeastward direction and the thickness of individual reservoirs decreases with the associated increase in reservoirs in a stratigraphic column.

The degree of oil saturation, high viscosity and the presence of basal water constitute production constraints and potential impediments to effective EOR technology. Other constraints include clay content within the reservoir, permeability and thickness of the reservoir. The nature of the reservoir can effect recoverability significantly as suggested by the anticipated range of recovery of 15-20% in the Lindbergh/Cold Lake area as compared to the extremely high 50% reported at Peace River and Gregoire Lake. This supports Meyers' (1983, Handbook of Energy Technology and Economics) contention that current levels of technology indicate

that in-situ methods are extremely site specific and therefore the time required for a "pilot" to "commercial" transition may be significant.

Technology and the reservoir parameters in addition to the logistics or accessibility of the region, provide development constraints. Land holdings tend to be smaller in extent in the less remote areas and this tends to limit development project size. The major constraints on development (other than supply and demand) can be listed as:

i) Limited contiguous land position,
ii) Resource thickness and richness,
iii) Presence of basal water in excess of one meter, and
iv) Socio-economic/environmental concerns.

Generally speaking, the clastic reservoirs of the heavy oil/bituminous sand areas of Alberta are very-fine to fine grained, angular to subrounded quartz sands which have porosities in the order of 30% and may have variable clay content relating back to its environment of deposition. The Mannville Group represents a deltaic-shoreline-near-shore transgressive sequence of rocks which lie directly on a Pre-Cretaceous unconformity surface of significant relief and which has in turn been affected to some extent by solution of underlying older salt deposits. To the south, the increased number of discrete sands indicates an associated increase in sand lenticularity and decrease in regional continuity.

2.2 Lloydminster/Lindbergh

The Lindbergh area is considered as typical of the Lloydminster rather than the Cold Lake deposits on the basis that it is located midway between the two, is located within the transitional zone that is recognized by the ERCB to exist between the Lloydminster and Cold Lake

Figure 2.2 **Stratigraphic Nomenclature Of East Central Alberta**

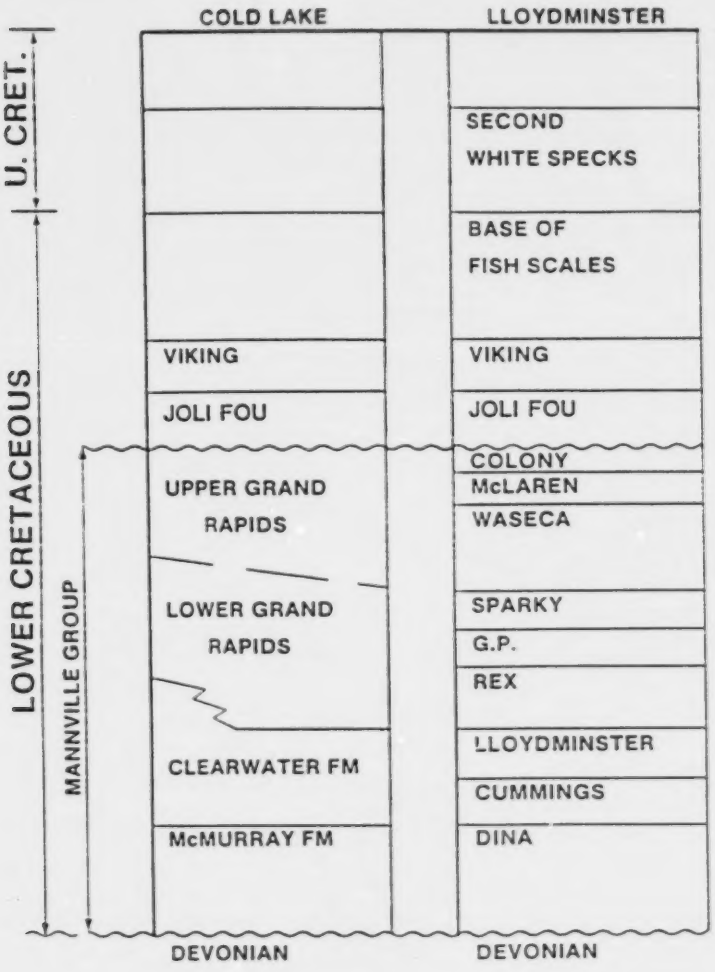
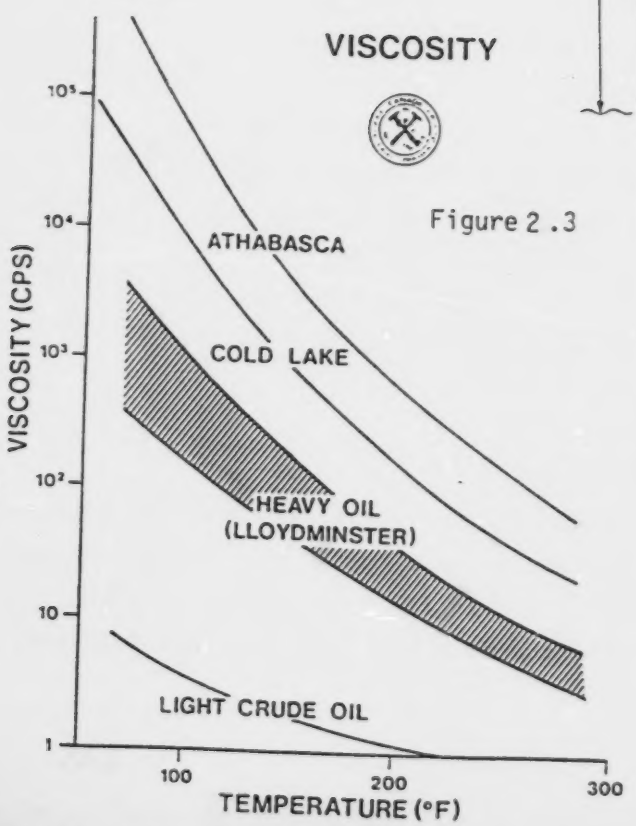


Figure 2.3



deposits, utilizes transitional nomenclature and is capable of primary production according to the Dome submission to the ERCB, hence making the Lindbergh deposit one of heavy oil rather than bituminous sand. The reserves of the Lindbergh area, however, must be assigned to the Cold Lake Oil Sands deposit in accordance with the ERCB designation.

2.2.1 Area 1170 mi^2 (2995 km^2)

As defined by the ERCB, the Lloydminster heavy oil deposit includes all heavy oil production areas bounded by Twp 37 on the south and Twp 52 on the north and extending from the Saskatchewan border on the east to Rge 9 W 4M on the west excluding the Wainwright military range. The Lloydminster heavy oil area, in this study, excludes all of the Saskatchewan reserves generally assigned to the Lloydminster deposit.

2.2.2 General Reservoir Parameters

This heavy oil area encompasses multiple reservoirs within the Mannville Group including from the top, the Colony, McLaren, Waseca, Sparky, General Petroleum, Rex, Lloydminster, Cummings and Dina Sands (see Fig. 2.2).

These sands can be generally described as an upward transgression from terrestrial to marine with an overall associated fining upwards sequence. However, the sands rarely are coarser than medium grained and tend toward the fine to very fine size range throughout. The shoreline migrated back and forth through the area, ultimately moving eastwardly across the area as the Lower Cretaceous sea transgressed.

As pointed out by Raicar & Procter (1980, GSC), the net oil-pay-thickness in the Alberta portion of the Lloydminster area ranges from 0-11m with the most frequent thickness of 1.5 to 3m. Rarely does net pay thickness exceed 6m. The significance of this is that to achieve an economically viable thermal EOR project, a

minimum net pay thickness in excess of 6m is essential. It is for this reason that only small scale pilot projects presently exist in the Lloydminster area. The advantage offered by thin beds and relatively high gravity hydrocarbons lies in technology development. Costs for experimentation can be offset by existing conventional production.

The gravity of the oil in the Lloydminster area varies between 10° and 26° API, but the most frequent gravities are between 13° and 18°. Viscosity is related to gravity and temperature such that lower API gravity oils undergo a greater decrease in viscosity with a given temperature increase than do higher API gravity oils (see Fig. 2.3).

Conventional production can yield recoveries in the order of 3% to 15% from reservoirs in the Lloydminster-Lindbergh Area prior to initiation of EOR. An additional 10% to 15% can theoretically be achieved by steam stimulation (Dome/Murphy) at Lindbergh and possibly more by moving on to the third phase of in-situ combustion. It has been suggested by Raicar & Procter (1980) that recoveries approaching 50% of the original oil in place (OOIP) can ultimately be realized. This position is supported by figures published on Amoco's Gregoire Lake pilot using the COFCAW Process. It is significant to point out, however, that the relatively thin nature of the reservoirs in the Lloydminster area is a deterrent to successful EOR projects and a size restriction on anticipated operations.

Other pertinent reservoir parameters include permeability, porosity, formation temperature, pressure and depth and formation volume factor. The values for formation temperature are case specific and average values can only reflect an approximation for an area. The temperature gradient in the Lloydminster area is in the order of 1.65-2.2°F/100 ft (3.0-4.2°C/100m) and the average formation pressure is in the order of 500 psi (3500 Kpa). The reservoirs of the Lloydminster area are generally between 1500-2000

ft. deep (450-610m), and have an average porosity of 30 percent and permeability of 350 to 1000 md. The oil formation volume factor throughout the Lloydminster area is slightly greater than unity and generally is in the order of 1.02 B/STB.

2.2.3 Reserves & Production

Reserve figures for the Alberta Lloydminster area as published by the ERCB amount to 0.946 x $10^6 m^3$ (ERCB 84-18). An NEB study (Nov. 83) has determined that of a total in-place (Saskatchewan and Alberta) reserve of 3.3 x $10^9 m^3$, 182 x $10^6 m^3$ is recoverable by tertiary steam flood and an additional 221 x $10^6 m^3$ can be obtained through in-situ combustion. The thickness of the reservoirs limits the effectiveness of the tertiary recovery methods. Historically the majority of production is exported to the northern tier of the U.S. although upgrading facilities are planned for the Lloydminster area, with a capacity of 50,000 BOPD.

2.2.4 Future Development

In the general Lloydminster area there are currently ten operators conducting EOR pilot operations. These operations include cyclic steam stimulation, steam flood, wet combustion (fireflood), caustic flood, and CO_2 flood. Three commercial projects in the Lindbergh area (Dome, Murphy, Amoco) have been given ERCB approval. Several other operators have plans for commercial ventures in the Lindbergh area, but the remaining Lloydminster area is still at the pilot stage. The generally thin reservoirs coupled with the checkerboard land picture and the relatively higher gravity oil makes this a good area for testing and developing technology for use in thicker reservoirs where higher returns are available.

The currently approved commercial ventures in the Lindbergh area account for an ultimate combined production rate in excess of 40,000 bbls/d (7130 m^3/d). If this is added to other pending

operations (e.g. PanCanadian, Westmin and others) a production rate in excess of 60,000 bbls/d (9540 m^3/d) is possible.

2.2.5 EOR Potential

As mentioned previously, the thin nature of the reservoir sands in the Lloydminster area tends to reduce the potential for single large scale enhanced recovery projects. Compared to the average reservoir parameters cited earlier for the Lloydminster area, comparable figures for Lindbergh suggest considerable more promise. Net oil pay thicknesses of 8-20m have been reported in the Lindbergh area with porosities slightly higher than reported as an average at Lloydminster. It appears that all other factors are similar even though some site specific variation occurs throughout the area. The prime consideration is reservoir thickness, and on this basis, Lindbergh provides considerablely more commercial promise than other areas in Lloydminster. The logical approach to EOR in the Lloydminster area is fireflood in the thin sands and relatively light oil while the thicker sands of Lloydminster and Lindbergh areas would be most suitable for cyclic steam stimulation or steamflood.

2.3 Cold Lake

The Cold Lake oil sands deposit lies intermediately between the Athabasca and Lloydminster deposits and incorporates the transition between the two, both in nomenclature and in oil gravity. The stratigraphic nomenclature of Central Alberta, as depicted in Figure 2.4 (see also Figure 2.2 for Lloydminster), suggests that Cold Lake nomenclature is distinct from that used at Lloydminster; such is not the case. The transition occurs within the northern portion of the Lindbergh area in Twp 57, which corresponds to the northern end of the Lloydminster area as defined by McCallum and Stewart in their 1978 study.

2.3.1 Area 518.4 mi^2 (134 x 10^3 ha)

The Cold Lake deposit includes bitumen and heavy oil accumulations in the Lower Cretaceous Mannville Group occurring within the area bounded by Twp 53 and 69, Ranges 1 & 8 W 4M. The deposit represents approximately 2492 x 10^3 ha of discontinuous reservoir.

2.3.2 General Reservoir Parameters

The Cold lake oil sands deposit is a multiple reservoir area; the reservoir sands include the Upper and Lower Grand Rapids, the Clearwater and the Wabiskaw-McMurray sand units. The average reservoir parameters for these units are contained in Table 2.3.

Table 2.3

General Reservoir Parameters
Cold Lake Deposit

Formation	Depth of Burial	Area (10^3 ha)	Wt.% O	% SW	Pay Thickness (m)
U. Grand Rapids	300-600m	816	26	45	6
L. Grand Rapids		669	26	43	12
Clearwater		532	30	33	10
Wabiskaw-McMurray		475	28	47	5

Regarding the environment of desposition, the lowermost reservoir unit, the McMurray, is dominantly fluvial at the base, becoming estuarine or lagoonal in an upwards direction, culminating in the fully marine Clearwater age glauconitic sand (e.g. the Wabiskaw). Marine conditions in the Cold Lake area continued throughout Clearwater time and into the Lower Grand Rapids. During this period conditions returned to a mixed marine-non-marine regime as suggested by the presence of coals and the lack of persistence in lateral facies. In the north (T63-69), the Clearwater appears to be the optimal reservoir for development, whereas the Grand Rapids (Lower) becomes the most plausible for development between T58 and 63. South of T58, the Cummings (Clearwater equivalent) becomes the horizon within which most development occurs. The lower reservoir pressures at Cold Lake reflect the slightly shallower nature of these reservoirs relative to those at Lloydminster, averaging 3220 Kpa. Specific values, available for several of the current projects in the area, are presented in Table 2.4.

Table 2.4

Formation Pressures in the Cold Lake Area

Operator	Formation	Formation Temp. (°C)	Depth (m)	Pressure (Kpa)	Permeability
BP (Wolf LK)	Clearwater	16	450	2800	
Murphy (Lindbergh)	Lower Grand Rapids	21	490	2700	2500 md
Dome (Lindbergh)	Cummings	25	600	3400	1500 md
Amoco (Elk Point)	Cummings	24	600+	4000	1860 md
Westmin (Lindbergh)	Cummings	24	N/A	3200	2500 md

2.3.3 Reserves & Production

The ERCB allocates the 33.30 x $10^9 m^3$ total reserves of the Cold Lake oil sands deposit to the various reservoir sands in accordance with Table 2.5. Assuming that predicted recovery rates of 17-20% are achievable by current technology, this deposit could yield 6.66 x $10^9 m^3$ of crude bitumen before new technological advancements are applied. According to Murphy Oil, the only operator currently with ERCB approval for commercial scale development in the Grande Rapids Formation, the potential for primary production is nominal. This compares with the BP statement "....in the naturally occurring state, the bitumen present in the Clearwater Formation can not be recovered economically by conventional production techniques". A similar statement has been made by Esso. In the Lindbergh portion of the Cold Lake deposit, Dome initiated its EOR efforts only after primary production had created the voidage necessary for enhanced steam stimulation. Dome projects that approximately 5% of the bitumen production can be achieved by primary methods. Amoco concurs but uses 4% as the ultimate necessary cold production. Current levels of production are generally

low with most of heavy oil and bitumen demand being met from conventional production in the Lloydminster area.

Table 2.5

Reserves Distribution Within
The Cold Lake Deposit

Upper Grand Rapids	$7.40 \times 10^9 m^3$
Lower Grand Rapids	$12.34 \times 10^9 m^3$
Clearwater	$10.14 \times 10^9 m^3$
Wabiskaw-McMurray	$3.42 \times 10^9 m^3$

2.3.4 Future Developoment

The Cold Lake oil sands deposit is recognized to have high development potential. In the northern portion of the deposit both Esso and BP are currently implementing heavy oil projects (huff and puff) which have ERCB approval to produce 56,600 bbls/d ($9000 m^3/d$) and 7000 bbls/d ($1100 m^3/d$) respectively from the Clearwater formation. In the central portion of the deposit, production tends to occur in the Grand Rapids Formation as indicated by the Murphy Oil operation at Lindbergh and the Suncor/Canadian Worldwide Energy operation at Fort Kent. Murphy has recently been granted ERCB approval for an in-situ recovery operation of 10,000 bbls/d ($1600 m^3$). In the south, in the Elk Point-Lindbergh area, two other operators, Dome and Amoco, have been given ERCB approval for EOR projects. Dome plans to extract 12,000 bbls/d ($1900 m^3/d$) from the Cummings sand while Amoco plans to develop the first phase of a 3 phase recovery project with an ultimate potential production level of 15,000 bbls/d ($2425 m^3/d$) averaged over the 20 year life the project.

Potentially, the Cold Lake area offers considerably more production potential than suggested above, but achieving the potential is dependent on a large number of factors:

i) demand
ii) price and cost efffectiveness, and
iii) technology.

Current activity related to EOR of Cold Lake deposit reserves

involves more than 15 operators, each of whom is likely capable of achieving a commercial scale operation. Several, including PanCanadian, Westmin, Canadian Worldwide, Canadian Occidental and Amoco have indicated that commercial projects are on the drawing boards for the early to mid 1990's. Esso has indicated that its ultimate goal at its Cold Lake project is a daily production level of approximately 160,000 bbls/d (25,450m^3/d) while other operators have suggested that either through increased production levels at existing sites, or through new operations, an additional 100,000 bbls/d (15,900m^3/d) can be produced. Ultimately the market place will determine the extent of development.

2.3.5 EOR Potential

The Cold Lake oil sands deposit lends itself readily to enhanced oil recovery technology. With oil gravity mostly in the 10-12° API range but reaching 15°, and reservoir thicknesses of 10 to 12m, the Lower Grand Rapids and Clearwater sands are amenable to most current EOR technology. The increased reservoir thickness over that encountered at Lloydminster tends to encourage the implementaion of steam as a first phase technique. The general absence of basal water further enhances this approach. Current technology favours using huff and puff (cylic steam) as phase one, followed systematically by steamflood and in-situ combustion.

2.4 Athabasca-Wabasca

The Athabasca-Wabasca oil sands deposit was first discovered in surface exposure by early fur traders and the original description was in 1792 by Alexander MacKenzie. The first recognition that hot water might be utilized for bitumen extraction was presented by Dr. Robert Bell in 1882. The first attemp to produce oil by an in-situ method was initiated in 1920. Shortly thereafter, Clark and Blair built the first hot water extraction pilot plant in Edmonton. The first attempt at commercial development was initiated in 1927 with the formation of the International Bitumen Company. From these early beginnings, technology and lease development have continued.

2.4.1 Area

The Athabasca-Wabasca deposit is the largest accumulation of bituminous sands in Canada encompassing an area of 11,000 mi^2 (28400 km^2) extending from latitudes 55° to 58° between the 4th and 5th meridians. In terms of reservoir area as calculated by the ERCB, the Athabasca-Wabasca deposit represents approximately 7200 x 10^3 ha of bitumen saturated Mannville sands and Grosmont carbonates.

2.4.2 Reservoir Parameters

The Athabasca-Wabasca oil sands deposit is a multiple reservoir case similar to those encountered at Cold Lake and Lloydminster except that in this area the Devonian Grosmont carbonate sequence, which unconformably underlies the Cretaceous clastic reservoirs, also is credited with recoverable reserves. Bitumen has also been reported from the Upper, Middle and Lower Grand Rapids, and the Wabasca and McMurray formations of the Mannville Group. Unlike the other deposits, the Athabasca-Wabasca deposit is complicated by the fact that portions of the reserves are accessible to surface mining and other reserves are neither accessible to surface mining nor current in-situ techniques due to depth of

burial considerations. The reservoir parameters of interest are delineated in Table 2.6. The Grand Rapids sandstones have a heterogeneous mineral composition. It probably represents shallow marine depositional conditions. The Wabasca is the marine sandstone member of the Clearwater Formation and contains primarily quartz and glauconite. It tends to be fine-grained, well sorted, with a high silt-clay-sized matriz. The McMurray sands are characteristically a terrestrial clastic to deltaic shallow marine transition.

Table 2.6

Athabasca-Wabasca
Average Reservoir Parameters

Formation	Depth of Burial	Area (x 10^3 ha)	Wt.% O	% SW	Pay Thickness
Wabiskaw-McMurray	0-20m		30	30	36m
	20-40m		30	30	38m
	40-80m	4475	30	30	36m
	80-120m		30	30	42m
	*80-750m		25	38	19m
U. Grand Rapids	150-450m	334	26	47	9m
M. Grand Rapids	150-450m	182	25	31	5m
L. Grand Rapids	150-450m	173	24	52	6m
Grosmont	200-500m	2031	20	33	5m

* 83% of total reserves are represented in this category

Open pit mineable reserves are those whose depth of burial is less than 50m and in-situ recoverable reserves are limited by the requirement that at least 100m of overburden must be present to prevent environmental damage resulting from surface breakthrough.

2.4.3 Reserves & Production

The ERCB divides the 241.5 x $10^9 m^3$ in-place reserves of the Athabasca-Wabasca deposit into formations in accordance with Table 2.7. Of this total, approximately 25 x $10^9 m^3$ is located within the designated surface mineable area while the remaining 216 x $10^9 m^3$ is available for recovery by in-situ methods and underground mining techniques. Current commercial production comes exclusively from

the surface mining operations of Suncor and Syncrude which amounts to 65,000 bbls and 105,000 bbls per day respectively.

Table 2.7

Bitumen Reserves - Athabasca-Wabasca

Formation	IVIP (initial vol. in place) $x10^9 m^3$
U. Grand Rapids	41.40
M. Grand Rapids	1.41
L. Grand Rapids	1.22
Wabiskaw-McMurray	147.00
Grosmont	50.5

2.4.4 Future Development

The Athabasca-Wabasca oil sands deposit offers the greatest potential for future development. However, because of logistics, product demand, surface mineable accessibility and the heavier nature of the oil (8° API rather than the 10° API at Cold Lake), this area will likely be the slowest to achieve commercial levels of in-situ production. Currently over a dozen pilot schemes are operational which represent in excess of 65 research years by seven different operators. Any one of these projects could be expanded to commercial size as land holdings in this deposit are relatively large and more contiguous than in the less remote areas.

Potential developments planned for the Athabasca-Wabasca deposit include commercial scale ventures in each of three areas:

i) Athabasca (Canterra-Tenneco).
ii) Wabasca (Gulf), and
iii) Carbonate Triangle (Union, Suncor)

By 1995 each of these new operators could produce a minimum of $4,800m^3/d$ (30,000 bbl/d) assuming no major changes in the plans. Other operators including Texaco, Amoco, Alberta Energy and PetroCanada have indicated future development on their properties is under consideration.

2.4.5 EOR Potential

The enhanced oil recovery potential for the Athabasca-Wabasca deposit must be considered by area. Within the surface mineable area, Suncor and Syncrude have current commercial operations, other potentially significant deposits exist at the Alsands, Home Oil-Alminex and PetroCanada Daphne leases, At each site, approvals have been given but operations are being held in abeyance pending improved economic conditions.

In-situ operations by Amoco at Gregoire lake developed the Combination of Forward Combustion and Waterflood (COFCAW) scheme of enhanced recovery which resulted in recoveries in the 55% of OOIP range (Meyers, 1983). Testing conducted by Canterra-Tenneco using a modified steam injection system suggests that with 8° API oil, the costs of operating at Athabasca are approximately 25% greater than similar operations at Cold lake although still within acceptable limits.

In the Wabasca portion of the deposit, Gulf, the sole major experimenter, has noted that a reservoir thickness in the order of 7.5m exists. They indicate that basal water is absent. To date, Gulf's experimentation has been inconclusive as to the optimal type of stimulation for reservoirs in the area, but currently favor

in-situ combustion with water injection to generate a steam bank in front of the burn (i.e. COFCAW). Gulf currently feels that demand constraints rather than reserves or recovery factor is the limiting factor to development and has scaled down the pilot project by a factor of four.

In the carbonate triangle, Union Oil has experimented with bitumen extraction from the Grosmont reef complex. Most of their produced bitumen has been reinjected into the formation rather than upgraded because of limited volumes. However, Union believes that commercial scale production is achievable. Currently, a "demonstration pilot" for tax reasons is preferred. Union favors huff and puff as the initial phase of EOR technology to be implemented in their carbonate triangle operations. Early in-situ combustion will be used as a follow-up phase.

2.5 Peace River

2.5.1 Area

The Peace River oil sands deposit was first encountered in boreholes by Shell in the early 1950s. Subsequent drilling for conventional oil and gas, coupled with delineation work by Shell, confirmed the widespread nature of the deposit. Shell has been actively conducting feasibility studies on the production of bitumen from this area since 1979.

The Peace River oil sand area constitutes the westernmost bituminous sand deposit in Alberta. The deposit lies east of the town of Peace River and extends in a strip southeastward from Twp 86, Rges 18-23 W5M to Twp 78, Rges 11-15 W5M with a tentacle extending southwestward from just east of Peace River. The deposit encompasses some 2000 square miles (5120 km^2).

2.5.2 General Reservoir Parameters

Data on the Peace River deposit is primarily available from Shell, the major land holder in the area. The bituminous sands of the Peace River deposit are confined to the Lower Cretaceous Bluesky and underlying Gething Formations of the Bullhead Group. This clastic sequence unconformity overlies subcropping Jurassic, Permian and Mississippian strata and pinches out against Mississippian carbonates to the northeast. The overlying marine shales of the Spirit River Formation provide an updip seal. The Bluesky Formation consists of well sorted, well developed, fine to medium grained, glauconitic sands which have been interpreted to be a marine reworking of Gething sands or a marine facies equivalent of the uppermost foothills Gething beds. The Gething Formation consists of poorly sorted, discontinuous sandstones with shales, siltstones, the occasional coal and local chert pebble beds. It may represent an alluvial sequence with a western provenance.

The major bitumen accumulations of this deposit are along a northwest-southeast trend of thick clean sands paralleling the updip depositional pinchout edge. Within this portion of the deposit, the reservoir is 24-27m thick (average 25m), comprised of loosely consolidated sand which is nearly uniform vertically and with good lateral continuity. There is a tendency for slight upward fining. Porosity averages 27% over the pay zone and tends to increase with increased bitumen saturation. Shell notes that, unique to the Peace River deposit, there is a zone of increased permeability and water saturation in the basal portion of the pay zone. In this zone, bitumen saturations are less than 65% of the pore volume and water will flow on drill stem tests. The 65% bitumen saturation is considered as the uppermost limit for free water flow.

The average reservoir depth in the Peace River deposit is in the order of 550m (1800 ft) although the depths range from 300m to 750m with expected reservoir pressures between 3750 and 4500 Kpa. The gravity of the bitumen is generally 7-10° API (usually 8-9°)

but can range from 6° up to 23°.

2.5.3 Reserves & Production

Bituminous sands of the Peace River area are estimated to have in-place reserves of 11.44 x $10^9 m^3$ (ERCB 84-18). Shell believes that this value is low by 5% to 25%.

Shell data indicates that the presence of the high water saturation zone at the base of the pay section can be utilized to distribute heat more effectively than would be otherwise possible and hence they feel that the current recovery rate estimate of 17% can be increased to 55% by utilizing this zone coupled with the pressure cycle steam drive currently in use and augmented by an initial steam multi-soak. Production from the Peace River sands is targeted for northern tier refineries in the U.S. and will be diluted and shipped without local upgrading at least until 1990.

2.5.4 Future Development

In the Peace River area only one operator, Shell, has actively pursued the development of heavy oil and bituminous sands. This operator has control of 62,000 ha within the deposit (nearly 240 sections) and has approval to develop 630 ha in an effort to increase current production levels from 200 to 1600 m^3/d (10,000 bbl/d). Discussions with Shell reveal plans to expand the current operation in the future, contingent upon future demand and the success of Phase I. Expansion could reach production levels in the order of 6400 m^3/d (40,000 bbl/d) by the mid 1990's and this volume could justify upgrading facilities located on site.

2.5.5 EOR Potential

Although the reserves figures published for this deposit are small when compared with Athabasca and even Cold Lake, the extensive land position held by Shell and its partners coupled with the

high anticipated recovery and the corresponding favourable logistics make development here far more realistic in the near term than in the more remote Athabasca deposit.

The relatively low gravity oil (8.4° average as reported by Shell), the presence of the basal heat conduit, and the thick and contiguous reservoir all increase the EOR potential of the area. In accordance with the findings of Wilson and Roots (1976), supported by Shell experimental data at Peace River, this deposit is well suited to steamflood techniques. Because of the low oil gravity, fireflood would tend to create excess coke during the burn process and hence not optimize recovery.

2.6 Summary - EOR Potential for all Heavy Oil and Tarsand Fields

2.6.1 Development Trends

In the Lloydminster area where nine potential reservoirs exist, 65% of the production currently can be attributed to three units, the Waseca, Sparky and General Petroleum sands. According to government studies only 33% of the total oil-in-place is found in reservoir sands with thicknesses in excess of 3 meters. Primary production results in less than 10% recovery due to low reservoir pressures, high viscosities and low initial dissolved gas content. Bottom water is commonly present. All of these factors support the contention that this area is better suited to in-situ combustion technology than steam stimulation as an EOR approach.

In the Cold Lake deposit (including Lindbergh) with the Lower Grand Rapids and Clearwater sands achieving reservoir thicknesses of 10 meters or more, steam stimulation is more adaptable. The Upper Grand Rapids and McMurray-Wabiskaw sands are considerable thinner and have higher water saturations and as such are less prospective and amenable to current steam based EOR technology. Recovery factors between 15 and 20% are accepted by operators in this area, but indications are that Esso anticipates recoveries near 50% (similar to that currently achieved by primary methods

with light oils) for the later phases of the Esso Cold lake Project (Phases 7-15). This may reflect the implementation of secondary or even tertiary EOR technology on the project following the current cyclic steam method.

At Peace River, Shell is utilizing a pressure cycle steam drive approach rather than the soaking favored at Cold Lake. This operator has the possibility of achieving a 55% recovery by this technique. This has been projected from their field proven recovery of 17% by extrapolating current performance through additional pressure cycles in accordance with simulators and model forecasts. Shell personnel feel this technique can be coupled with a pre-soak to achieve optimal recoveries. This process is enhanced by the wet interval at the base of the pay zone which will effectively spread the heating front to larger portions of the reservoirs than would be achievable under different reservoir conditions.

At Athabasca-Wabasca, the development of in-situ production may be stalled by potential surface mine development while the optimal method of in-situ extraction is still in doubt. Gulf, at their Pelican Project, are still experimenting with spacing but currently they favour in-situ combustion with a steam bank in front of burn - i.e. COFCAW. Amoco at Gregoire lake has established that the COFCAW Process can achieve 50% recovery but they are currently experimenting with steam injection. Union has a huff and puff pilot currently operative and believe, as a result of field testing, that in-situ combustion in the carbonate triangle is an effective <u>follow up</u> step to a form of steam stimulation.

It would seem that steam as a first order EOR approach followed by in-situ combustion or a combined approach (e.g. COFCAW) constitutes the generally accepted thermal medium for extraction of bitumen at Athabasca-Wabasca, Cold lake and Peace River. However, experimentation continues utilizing foam diverting agents and inert gases to enhance the steaming process and these results are still far from conclusive. Each site is different and, hence, responds

Table 2.8

PRODUCTION POTENTIAL OF HEAVY OIL AND OIL SANDS AREAS
Alberta In-Situ Projects
(m3/d)

Map Reference Number	Area & Company	Expected Life (years)	Production Level			
			Current	Additional Planned	Additional Possible	Total
	ATHABASCA					
1	Gulf	20	160	1,640	0	1,800
2	PCEJ	20	0	0	3,200	3,200
3	Union	10	0	0	2,400	2,400
10	Canterra	25	0	1,600	0	1,600
	Sub-total		160	3,240	5,600	9,000
	COLD LAKE					
5	Suncor	15	520	80	0	600
6	Esso	25	6,360	18,640	0	25,000
7	CanOxy	30	0	200	0	200
8	AEC/Esso	20	0	1,600	0	1,600
9	BP	23	480	5,020	0	5,500
11	Bow Valley	20	0	160	2,340	2,500
12	Drummond		15	0	185	200
13	Koch	20	0	160	3,040	3,200
14	Mobil		0	0	2,400	2,400
15	Petro-Canada	20	300	500	800	1,600
16	Dome		0	0	1,600	1,600
18	Husky	20	0	600	1,600	2,200
	Sub-total		7,675	26,960	11,965	46,600
	LINDBERGH/LLOYDMINSTER					
4	Amoco	25	0	4,800	0	4,800
17	Murphy		0	1,600	0	1,600
19	Westmin	30	0	500	1,600	2,100
20	Dome	20	600	5,000	1,600	7,200
21	PanCanadian	15	0	3,000	1,600	4,600
	Sub-total		600	14,900	4,800	20,300
	PEACE RIVER					
22	Shell	30	160	6,240	0	6,400
23	Chieftain		0	0	1,600	1,600
	Sub-total		160	6,240	1,600	8,000
	TOTAL		8,595	51,340	23,965	83,900

differently to the same type of stimulation. The differences are compensated by well spacing and configuration, varied steam injection rate, period and slug size and production cycle length. However most operators agree that in-situ combustion is the final step as the combustion process destroys that which is not produced. Although the steaming processes do not at this time solve the problem of ultimate optimal recovery, they result in acceptable levels for a first pass and are amenable to modification as technnology improves.

2.6.2 Summary of Enhanced Hydrocarbon Production Potential

The production potential of the enhanced heavy oil and tar-sand desposits is very large and can undoubtedly expand dramatically given favorable economics, certainty of markets and the willingness by the industry to commit the massive funds to these projects. The data presented on Table 3.8 represents those known or potential projects with production potential in excess of 800 m^3/day.

At present, the total production of 8600 m^3/day represents only 17% of the planned production and about 10% of the total production potential as defined by industry personnel. The largest expansions will occur at Cold Lake (Esso and BP), Lloydminster (Dome) and Peace River (Shell). This analysis has developed a conservative approach to the possible production and based upon that, the poorly defined or undefined projects will not add substantially to the future production (less than 3 times the current production).

Regionally, Cold Lake claims (by far) the greatest share (60%) of production potential. Lloydminster ranks second in importance with Peace River and Athabasca each containing about 10% of production potential.

2.7 FUEL DEMAND FOR STEAM RAISING

Given the projected production levels of tarsand and heavy oil and assuming the planned levels are minimums and the total level is the maximum, the energy requirements are shown on table 2.9. The data indicates that if all the energy requirements shifted to natural gas, it would represent about 10% of present annual production. With coal, however, the energy requirement represents 70% to 110% of present plains coal production. Coke supplies cannot come even close to meeting the total energy demand and can be considered for only one or two large projects.

Table 2.9

Fuel Demand for Steam Raising at
Enhanced Hydrocarbon Recovery Projects

	Energy Demand/Year		% of Present Annual Production	
Fuel Type	Minimum	Maximum	Minimum	Maximum
Natural Gas	240 pjoules	295 pjoules	9.5%	11.8%
Coal	10.5 megatonnes	17.3 megatonnes	66.9%	110.2%
Coke	6.3 megatonnes	10.4 megatonnes	460%	760%

3.0 FUEL SUPPLIES AND PRICING FOR ENHANCED RECOVERY PROJECTS

3.1 LEASE CRUDE

Lease crude has a market determined value to the producer. If lease crude is used as a fuel for EOR, the opportunity cost is assumed, in this study, to be the market value reduced by production costs. It is assumed that the oil is royalty free for consumption at the steam raising plant. Production costs and crude market value vary widely from region to region, nevertheless, a standard reference value of $\$125.80/m^3$ ($20/bbl) has been used for all heavy oil regions. No additional operating costs for de-sulphyrization are assumed. The on site distribution costs are assumed to be similar to natural gas. In spite of these favorable assumptions, lease crude has a very much higher opportunity cost than any other fuel source.

3.2 PETROLEUM COKE

3.2.1 Introduction

Petroleum coke is the residue left after the destructive distillation of crude petroleum. This product tends to be rich in carbon, metals and sulphur. Because of the extremely high carbon to hydrogen ratio, petroleum coke has a relatively high calorific value when compared with other solid fuels. Petroleum coke is of interest to this study because it can be burned in FBC units and has few competing applicaitons beyond source fuel requirements.

3.2.2 Supply

There are currently two commercial sources of petroleum coke in Alberta; the Suncor and Syncrude operations at Fort McMurray. The Husky Upgrader at Lloydminster will produce coke as a by-product of the upgrading operations when it comes on stream. Based on data provided by the operator, Suncor's Tar Island delayed coking process uses about three quarters of the total produced green coke for power generation and the remainder is stockpiled. Syncrude's Mildred Lake fluid coking process use only about one quarter of the total produced coke as fuel in the fluid cokers and the remainder is stockpiled.

3.2.2.1 Government Input

The ERCB stipulates that coke and sulphur constitute resources which have future value and have not allowed disposal of these by-products at either the Suncor or Syncrude sites. Furthermore, the Board requires that an operator apply for and obtain approval for the storage or disposal of any oil sands, coke or discard associated with the extraction processing and/or upgrading of bitumen.

3.2.2.2 Production Rates and Reserves

Including all three sources of petroleum coke, a substantial amount is available. The Husky upgrader is reported to be capable of producing 410 tonnes/day in excess of operational needs which equates to nearly 150 kilotonnes/year. Suncor is reported to have in the order of 2,150 kilotonnes currently stockpiled. Syncrude presently has approximately 3,000 kilotonnes currently in wet pond stockpiles, and excess coke is sluiced into storage ponds at a rate of about 2.5 kilotonnes/day.

3.2.2.3 Quality Data

The analytical data for coke are different at each source as indicated on Table 6.1.

Table 3.1

Coke Analyses

Data	Suncor	Syncrude	Husky
Ash %	2.9	7.1	0.5
S %	5.9	6.8	3.0
Volatile Matter %	9.0	N/A	10.0
F.C. %	76.7	91.3	N/A
Heat Content (MJ/kg)	33.5	29.5	N/A

Coke has a heat content equivalent to high rank bituminous coal but this energy value is offset by the very high sulphur content.

3.3 NATURAL GAS

3.3.1 Introduction

Natural gas has demonstrated itself to be the preferred fuel for industrial uses in Alberta. It burns cleanly, has good calorific value, and is convenient to handle and transport. It lacks the adverse social stigma and environmental qualities of nuclear energy and the solid bulk fuels. With the present daily supply/demand picture, natural gas is favored by the present heavy oil and tarsand operations. Negative aspects of natural gas as a steam generator fuel are:

i) high opportunity cost and
ii) regulatory uncertainty.

3.3.2 Supply

There are numerous estimates available on the quantity and quality of natural gas reserves in Alberta. These are available from organizations like the NEB, the ERCB and other provincial sources, and the CPA. The CPA estimates tend to be optimistic, reflecting operator input. The ERCB and other provincial agencies tend to be more conservative in allocating reserves. The NEB also arrives at an independently derived reserve figure. The latter tends to fall between the other two sources and therefore represents a median view.

The reserves of natural gas attributed to Western Canada (excluding frontiers) estimated by the NEB as at December 31, 1981 was 80.714 exajoules (1 EJ/0.95 Tcf) with 61.618 EJ (approximately 75%) of that total controlled (contracted). By the end of 1983, the total established reserves had increased to 81.4 EJ, of which 69.3 EJ (approximately 85%) was located in Alberta.

The NEB (1982) estimates an ultimate marketable potential of 147.6 EJ for Western Canada including frontier regions. Cumulative production to date has been 49 EJ, leaving a remaining potential reserve of 99 EJ (NEB 9-84). Marketable gas reserve additions in conventional areas are estimated to be 45.7 EJ.

Estimates made by the NEB following the 1982 Omnibus Hearings, project a total reserve of 63.5 EJ by the year 2000. As a result of the recessionary economy, increased prices and increased conservation measures, natural gas exports since 1982 have averaged only 40% of authorized levels. The NEB suggests that this should increase to about 90% of authorized volumes by 1990, however deregulation may increase the exports above levels suggested by NEB, as indicated by current market trends. At present a large surplus exists. In the intermediate-to long-term it may be more economic to export natural gas rather than burn it for steam generation.

The reserves of natural gas that occur near to the chosen tarsand/heavy oil demand centers are listed in Table 4.1. Because of the extensive natural gas pipeline network in Alberta, exchange agreements render the source of natural gas less relevant.

3.3.3 Demand

NEB estimates of Canadian exports of natural gas have remained steady at 1.0 EJ/year for several years. Canadian consumption of gas is about 1.5 EJ/year and thus total annual demand for Canadian natural gas is about 2.5 EJ/year. This represents a demand that will consume the Canadian supply in about 30 years if no new supply was provided. At present, new supply is contributing about 5 EJ/year thus the reserve life is increasing by about 1 year annually and the surplus is growing. This inventory accumulation cannot continue without sales to support it.

Table 3.2

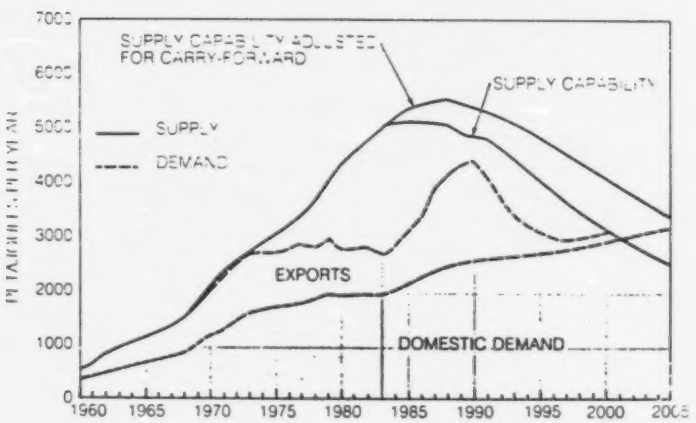
Natural Gas Reserves in Heavy Oil Areas

Location	Field Name	Reserves ($10^6 m^3$)	Reserves (EJ)	Heavy Oil/ Tarsand Demand Centre
84-14W5	Slave Lake	208	7.7	Peace River
82-14W5	Seal	569	22.3	
80-16W5	Dawson	216	8.077	
86-19W5	Cadotte	318	11.902	
79-20W5	Kimiwan	182	7.250	
78-18W5	Roxana	646	25.680	
80-22W5	Normandville	1159	45.273	
79-24W5	Culp/Eaglesham	790	31.680	
80-24W5	Tangent/Nova	1714	64.251	
83-23W5	Grimshaw	179	6.816	
Total		5981	23.056	
84-09W4	Hangingstone	1561	58.384	Central Athabasca
80-09W4	Corner	3	.112	
81-05W4	Newby	1274	54.527	
79-04W4	Graham	666	28.627	
81-05W4	Chard	1232	52.276	
77-09W4	Leismer	6117	228.746	
82-15W4	House	1643	60.882	
83-18W4	Cramer	527	21.559	
86-18W4	Saleski	699	26.103	
93-21W4	Liege	3799	142.980	
84-11W4	Athabasca (21 pools)	1001	37.301	
Total		18522	711.497	
57-05W4	Lindbergh	3070	114.727	Cold Lake/Lindbergh
56-06W4	Elk Point	175	6.484	
59-04W4	Muriel Lake	338	12.651	
59-06W4	Kehiwin	743	27.850	
56-06W4	Cold Lk/Lindbergh (10 pools)	441	16.506	
Total		4767	178.218	

(from ERCB 84-18)

If international demand for Canadian natural gas increases as expected due to deregulation of the industry, the export sales could surpass the projected 90% of authorized exports by 1990 (a significant increase above the present export volumes). With the 2% historic rise in domestic sales continuing and the more rapid export sales increase, natural gas production could hit 4.5 to 4.8 EJ/year by 1990. This fits well with the projected supply/demand curves provided by the NEB Curve on Fig. 3.1.

Fig. 3.1
Natural Gas Supply and Demand
Conventional Producing Areas



3.3.4 Pricing

Historically pricing of natural gas was controlled by the Alberta Petroleum Marketing Commission for all gas leaving the province. Within the province, a free market has existed. The relaxing of this controlled environment with deregulated pricing outside Alberta will make the market within Alberta more responsive to worldwide fluctuations in price. Sales within Alberta will only occur at a discount as long as local suppliers perceive that they can not penetrate the more lucrative markets ouside Alberta.

The provincial government implemented royalties averaging 30-40% on natural gas production in 1974 with the actual amount

dependent on productivity. The Province also adoped an industrial fuel policy which discouraged the use of natural gas for industrial purposes. Since that time, economics have encouraged a relaxing of the application of the industrial fuels policy with respect to use of natural gas in the heavy oil and tarsand steam injection applications.

Subsequent to the 1981 Esso Cold lake hearing, the ERCB has allowed natural gas to be used to generate steam for EOR projects. Natural gas produced by an EOR operator and used in an approved EOR project is eligible for a Crown royalty rebate.

Recent governmental changes in royalties have not been in existence long enough to have measureable effect on the industry, but the changes include:

i) an increased royalty tax credit for small producers,
ii) a termination of the APIP program,
iii) a marginal decrease in royalty rate from 45% to 40% and 35% to 30% on old and new production, respectively, and
iv) a 12 month royalty holiday or a royalty exemption based on a depth related schedule.

These incentives are intended to allow benefits derived from the Western Accord to flow through to the industry. According to the CAODC, the incentives should be reflected in increased drilling activity. IPAC noted the increase in royalty tax credits is critical to small exploration companies because of adverse legislation in the Western Accord. The consensus is that the new royalty rates on oil will substantially improve the economic outlook of the industry and thereby increase the industry capacity to undertake EOR projects.

The present average export price of natural gas is about $3.10 U.S./Mcf export, and $2.94 Canadian/Mcf at the Alberta border. This study assumes a 10% discount below Alberta border price or a price of $2.65/Mcf ($93.58/m^3). For application to the steam injection sites the following assumptions are used:

i) Delivery point: EOR project site lease boundary within Alberta.
ii) Pricing environment in 1990:
- gas to gas and gas-to-alternate fuel competition eliminates domestic/export price differential, i.e. no export flowback.
-longer term gas contract prices at 90% of Alberta border price (versus 70%-80% today).
- current Alberta border price: $2.94/Mcf ($2.79/GJ).
iii) Gas supply situation: subsequent surplus availability to permit exports.
iv) Price includes producer (wellhead) price plus transportation.

The assumed gas opportunity cost of $2.65/Mcf is not intended to reflect the lifelong costs of consumer-owned gas, but is intended to reflect the market value at which it could be sold if not conserved for steam generation. In the 1990's time frame, it is assumed that natural gas could always be sold into either the domestic or export market for at least $2.65/Mcf. Lifting costs are incurred whether or not the gas is burned or sold. Royalties are paid only if the gas is sold. A major assumption of this study is that much of the natural gas consumed in steam generation is purchased on a royalties-paid basis, as are the coal and coke fuels.

3.4 COAL

3.4.1 Plains Coal in Alberta

3.4.1.1 Distribution of Deposits

Five major coal zones occur in the plains region of Alberta. From oldest to youngest, these zones are designated by the ERCB as the Taber, Lethbridge, Lower Horseshoe Canyon (Drumheller), Carbon-Thompson and Ardley. They are associated with beds in the Belly River and Edmonton Groups of Upper Cretaceous age and the Paskapoo Formation of Tertiary age. Other Lower Cretaceous coal bearing strata are recognized but are at too great a depth to be accessible by surface mining techniques.

The two major coaliferous zones, the Ardley and Horseshoe Canyon crop out in arcuate subparallel bands which trend NW-SE. The Ardley Trend extends from Fox Creek/Simonette to south of Red Deer in west-central Alberta and represents the subcrop edge of the Paskapoo Formation. The Horseshoe Canyon coal trend extends from Lesser Slave Lake to Drumheller in east-central Alberta and then southwestward to McGregor Lake parallel to and approximately 50 miles east of the Ardley Coal Zone. The Horseshoe Canyon trend corresponds to the subcrop edge of the Edmonton Group.

The strata encompassing these coal measures dip gently to the west (5m/km) and lie on the east flank of the Alberta Syncline. Lateral continuity of individual seams is variable, but the coal zones are generally persistent over large areas and individual seams may attain thicknesses of up to six (6) metres. Locally, thicknesses of up to 12m have been reported.

The Drumheller coal zone attains mineable thickness south of Red Deer at a stratigraphic horizon between the Ardley Coal Zone and the Lower Coaly Zone of the Horseshoe Canyon Formation. The Taber and Lethbridge coals follow an arcuate trend associated with deposition controlled by subsidence of the Sweetgrass Arch in southern Alberta.

3.4.1.2 Coal Reserves and Rank

Approximately 95% of the coal resource base of 2600 gigatonnes (10^9) is equally distributed between the Ardley and Horseshoe Canyon coal zones with the remainder divided between the other three zones. Of the total resource estimate for the plains, only 31% (800 gigatonnes) is considered potentially recoverable and of this figure only 0.9% (7.2 gigatonnes) is presently included in the identified reserves amenable to open pit mining.

Plains coals in Alberta are characteristically sub-bituminous, increasing in rank from C to B with increased proximity to the Front Ranges of the Cordillera. They also are characterized by low sulphur (ranging 0.2%-1.8%, but generally 0.3%-0.5%), with heat content in the order of 20 MJ/kg (4800 kcal/kg). Some lignite occurs near the northern and northeastern limits of the Taber and Lethbridge zones, in the southeastern deposits of the Cypress Hills region, and in the Peace River Country. High volatile C bituminous coal occurs in the Lethbridge coalfield.

3.4.2 Producing Mines

There are several major producing coal mines in Alberta. The largest mines occur in three areas: Wabamun, Battle River and Sheerness coal areas. These mines produced 18.2 megatonnes in 1984, of which virtually 100% of production went to local power

plants. This captive coal represents, for all present day purposes, an unlimited supply of very low cost (about $0.60/GJ) fuel to the power plants.

3.4.2.1 Wabamun Area Coal Mines

The two mines at Wabamun; Whitewood and Highvale Mines located in townships 53 and 52, ranges 4 to 6 W5M, lie near the Wabamun, Sundance and Keephills thermal power generating facilities owned by TransAlta Utilities. The reserves in the Wabamun area are estimated to be 280 x 10^6 tonnes in place with a mining ratio of about 5 bcm/trc. Expansion potential for these mines is represented by an additional 500 x 10^6 tonnes at somewhat higher ratios. The Wabamun coals occur in the Ardley Coal zone and have the following typical analyses:

H_2O	19.9%
Ash	16.7
V.M.	25.1
F.C.	38.3
Heat Content	18.2 MJ/kg
S	0.23%

3.4.2.2 Battle River Area Coal Mines

The Diplomat, Vesta and Paintearth mines are located in Townships 39 to 41, Ranges 15 and 16 W4M, in the Battle River area. The produced coal is delivered to the Alberta Power Battle River Power Plant and Saskatchewan Power's Queen Elizabeth Power facility in Saskatoon. The Battle River Mines' Permit Areas have in the order of 150 x 10^6 tonnes of reserves, however the Diplomat reserves are nearly exhausted. At present none of the three mines are operating at full capacity. The Battle River coals are characterized by the following quality data:

H_2O	26.0%
Ash	10.7
V.M.	27.6
F.C.	35.3
Heat Content	18.1 MJ/kg
S	0.50%

3.4.2.3 Sheerness Area Coal Mines

The Sheerness area mines includes the Montgomery and Roselyn Mines which are located in Township 29, Ranges 12 and 13 W4M. The production is dedicated to the TAU/APL Sheerness thermal generating facility. Estimates of the in-place reserves for these properties approach 135 x 10^6 tonnes, with the bulk of reserves in the Lower Coaly Zone of the Horseshoe Canyon Formation. Coal quality is more variable at this locality than at the other two areas. Typically, the coal analyses range as shown below:

H_2O	27.5%
Ash	5-35
V.M.	18-30
F.C.	20-40
Heat Content	16.7 MJ/kg

3.4.3 Potential Deposits for Oilfield Demand

There are several coal deposits within the Ardley, the Horseshoe Canyon and the Wapiti Formations which are delineated but are not producing that are considered representative for the current study. These deposits are included as potential source coals and are described in Appendix III. All of these deposits are potentially amenable to low cost dragline mining methods. It is assumed that the run of mine (ROM) coal will be marketed to the steam injection sites without beneficiation.

3.4.3.1 Fox Creek (CrowsNest Resources)

Fox Creek is located in Twp 64 to 66, R 16 to 18 W5M. Drilling has indicated a reserve of 238.9 x 10^6 tonnes of recoverable coal in seven separate deposits. Mining pre-feasibility studies are complete. The best deposit, Meekwap west (IIA)

contains 120 x 10^6 tonnes @ 5.3 bcm/trc. With a high ash content of 22.9%, the heat content of Fox Creek coal is 16.1 MJ/kg. It is suspected that, at slightly higher ratios, a substantially cleaner and higher heat content coal could be produced.

3.4.3.2 Isle Lake (TAU, PCP, CNRL, Manalta, Esso)

Isle Lake represents an extension of the Ardley Coal Zone to the northwest of the Whitewood and Highvale mines. Located in Twp 53 to 55, Ranges 6 and 7 W5M, these deposits can provide coal to the Wabamun Plant or meet new demands. Recoverable reserves of 120 x 10^6 tonnes with a <6 bcm/trc mining ratio represent a very substantial coal reserve base. A smaller but still substantial reserve of coal with <5.0 bcm/trc is known to be available. The coal rank and quality are similar to the Wabamun area:

H_2O	18.5%
Ash	21.2%
V.M.	25.8%
F.C.	34.6%
S	0.23%
Heat Content	17.2 MJ/kg

3.4.3.3. Genesee (Fording, Edmonton Power, Warburg Coal)

The Genesee deposits are located on trend with the Highvale and Keephills Mine and south of the North Saskatchewan River. In this area the Ardley Coal Zone subcrop reserves are very large with 370 x 10^6 tonnes of coal with an open pit mine ratio of <6 bcm/trc and with substantial areas of lower ratio coal available. This sub-bituminous C coal quality and heat content is:

H_2O	20.0%
Ash	12.0%
V.M.	20.4%
F.C.	40.0%
Heat Content	18.8 MJ/kg
S	0.22

3.4.3.4 Heatburg (Fording)

The Heatburg Coal Deposit, located southeast of Red Deer, Alberta (Twp 37-41, R22-24 W4M) contains a very substantial and low ratio reserve, but the numerous coal partings result in a very high ash content. The reserve base is 477 x 10^6 tonnes at 4.5 bcm/trc with a typical analysis as follows:

Analysis	Mass Mining	Selective Mining
H_2O	18.0	17.6
Ash	26.5	14.7
V.M.	24.0	27.5
F.C.	31.5	40.2
Heat Content	15.8 MJ/kg	19.5 MJ/kg
S	0.30	0.25

Detailed feasibility studies for large scale mining operations have been carried out.

3.4.3.5 Barrhead (Luscar, Manalta)

The coal reserves in the undeveloped Barrhead deposits contain in excess of 100 x 10^6 tonnes with mining ratios of 10 to 11 bcm/trc in this Horseshoe Canyon Coal Deposit. It is expected that initial development at low tonnage can access some lower ratio material. Reported coal quality is:

H_2O	25.5%
Ash	11.4%
V.M.	29.0%
F.C.	34.0%
Heat Content	18.2 MJ/kg
S	0.5%

Although both companies have completed a substantial amount of exploration, mining feasibility studies have not, as yet, been completed.

3.4.3.6 Morinville (PCP, CNRL, Luscar, Fording)

The Morinville Deposit is located in Twp 55 to 58, R24 to 26 W4M and lies on the subcrop line of the Horseshoe Canyon Coal Zone. The ERCB reserve estimate of 600 x 10^6 tonnes in six deposits at about 7 bcm/trc indicates a large mineable coal reserve. CNRL indicates a 466 megatonne reserve @ 8.2 bcm/trc and Fording indicates 71 x 10^6 @ 7.2 bcm/trc. Typical analyses are:

H_2O	24.3%
Ash	11.0%
V.M.	27.4%
F.C.	37.3%
Heat Content	18.1 MJ/kg
S	0.3%

Fording has carried out preliminary exploration, CNRL has carried out exploration and completed a pre-feasibility study on their property.

3.4.3.7 Tofield - Camrose-Ryley (Fording, TAU, Luscar)

The +340 x 10^6 tonne deposit in this area represents an immense coal reserve of Horseshoe Canyon Coals at moderate mining ratios of 6.4 bcm/trc. The coal quality is:

H_2O	26.0%
Ash	11.0%
V.M.	28.1%
F.C.	34.6%
Heat Content	18.3 MJ/kg
S	0.5%

Numerous mine feasibility studies and a major mine application process in 1976 provide a wealth of data. It is expected that a small tonnage mine can locate relatively large areas of low ratio (5 bcm/trc) coal deposits.

3.4.3.8 Halkirk - Castor (Luscar, PCP)

Located in Twp 36 to 38, R14 to 16 W4M, these open pit mineable coal deposits lie immediately south of the Paintearth Mine along the Horseshoe Canyon Coal zone subcrop line. Numerous drillholes have identified a total of 460 x 10^6 tonnes at about 10 bcm/trc. With the large reserve area and nominal surface useage, it is not impractical to expect pockets of lower ratio material near the coal subcrop. Typical coal quality in this area is:

H_2O	25.0%
ASH	11.0%
V.M.	29.0%
F.C.	35.0%
Heat Content	18.1 MJ/kg
S	0.5%

Feasibility studies have not been carried out on any of these deposits.

3.4.3.9 Thorhild

The Thorhild coal deposit is located in the area surrounding T59-R24 W4 and represents the coal deposit that lies nearest to the Cold Lake and Lindbergh Heavy Oil and Tarsand Demand centres. Coal reserves in this series of deposits is listed as 10 megatonnes recoverable by open pit methods by the ERCB. Fording indicates 4.19 megatonnes @ a modest 3.62 bcm/trc strip ratio. The coal is subbituminous C, marginal on Lignite A with the following analysis:

H_2O	25.0%
ASH	7.0%
V.M.	29.0%
F.C.	39.0%
S	0.3%
Heat Content	4800 kcal/kg

3.4.3.10 Lesser Slave Lake (Luscar, Manalta)

Located in Twp 70 and 71, R2 to 4 W5M and Twp 75 & 76, R1 & 2 W5M, these lignite A coal deposits represent localized coal development within the Wapiti Formation. These deposits contain about 160 x 10^6 tonnes of coal lying in thin coal seams at 12.5 to 14.5 bcm/trc. Due to the thin coal seams, low ratio pit material will likely be about 8 bcm/trc. Typical coal analyses are:

H_2O	33%
Ash	5%
V.M.	27%
F.C.	35%
Heat Content	17.4 MJ/kg
S	0.2%

There have been no serious mining or economics studies carried out by any of the operators.

3.4.3.11 Clear Hills (Manalta)

The Clear Hills deposit lies in Twp 90, R6 W5M north of Worsley, Alberta. The coal is thought to be a lignite that occurs in the Wapiti Formation of Tertiary Age. It is expected that +20 x 10^6 tonnes of coal occur at a mining ratio of 10 bcm/trc to 15 bcm/trc. Analyses are not available however a heat content of about 15 KJ/kg can be expected. It is unlikely that these deposits have been studied in detail.

3.4.3.12 Judy Creek (TAU, Esso)

The Judy Creek Deposit contains 226 megatonnes of proven reserves with about a 5 bcm/trc mining ratio. The heat content is about 17 MJ/kg.

3.4.3.13 Other Deposits

There are numerous other deposits of surface mineable coal that are not included in this report. Details of these properties can be acquired from the Coal Department, ERCB and the various mining companies.

3.4.3.14 Summary of Coal Deposits

The tables below summarize the relevant reserve and quality data of the coal deposits included in this study.

Table 3.3

Summarized Coal Deposits

Deposit	Reserve (megatonnes)	Mine Ratio (bcm/trc)	Ash Content %	Heat Content (MJ/kg)	Zone of Occurrence
Fox Creek	120	5.3	22	16.1	Ardley
Isle Lake	+50	5.0	21	17.2	Ardley
Genesee	370	6.0	12	18.8	Ardley
Heatburg	477	4.5	26	15.8	Ardley
Barrhead	100	10.0	11	18.2	Horseshoe
Morinville	537	7.7	11	18.1	Horseshoe
Tofield-Camrose-Ryley	340	6.4	11	18.3	Horseshoe
Halkirk-Castor	460	10.0	11	18.1	Horseshoe
Thorhild	40	8.0	6	18.4	Wapiti
Lesser Slave Lk.	160	13.0	5	17.4	Wapiti
Clear Hills	+20	12.0	-	15.0	Wapiti
Judy Creek	-26	5.0 (?)	-	17.0	Ardley

The average higher heat content of the Horseshoe Canyon coals is primarily due to the lower ash content. It is noted, however, that the sulphur content of Horseshoe Canyon coals is commonly greater than the Ardley coals and this will affect capital and operating costs of burning.

3.4.4 Coal Prices and Production Costs

3.4.4.1 Historical Data

The average price of ROM sub-bituminous coal delivered to the power plants in Alberta in 1981 was $6.80/tonne. This value excludes capitalization of heavy equipment (which is included in the electrical rate base) and profit. More recent prices are not in the public domain, but escalation to 1985 prices results in a per tonne price of $8.80. This production is from some very large mines, for example Highvale produces over 8 megatonnes per year and can realize economies of scale to minimize the cost of coal. The other mines are more modest, with production in the 1 to 2 megatonne range. If capitalization and profit are included in this cost, the resultant cost in 1985 dollars will be in the order of $10.00 to $12.00/tonne.

Coal production in Alberta often includes a government royalty equal to about 5% of production costs, or, on average, about 50¢/tonne of coal mined. If the land is freehold, the royalty rate is often greater than the average crown royalty. In this study, we assume 2 X Crown Royalty or about $1.00/tonne.

With the cost of opening new mines, and the fact that annual coal demand for the heavy oil steam injection sector will be more varied, it is suggested that the price of coal would have to be marginally higher (by about 10%) than the present smaller dragline operations, and, accordingly, a new pit price of +$11.00/tonne is not unreasonable.

3.4.4.2 Mine Cost Derived Coal Price

Capital and operating costs are determined for a typical, but hypothetical, open pit dragline operated mine at an average production level of 2 million tonnes/yr. The overall strip ratio (including re-handle) is 7.57 bank cubic metres overburden/tonne raw coal (bcm/trc). All capital and operating costs were estimated using **STRIPMIN** pre-feasibility level cost estimating routines (see output in Appendix IV). The mine, at a two megatonne/year operating level, utilizes a single $34m^3$ bucket dragline, scrapers for pre-development, hydraulic shovels for coal loading, and 70 tonne coal hauling trucks. The total capital cost is $67.74 million, with a 23 year replacement schedule of $66.70 million (Appendix IV.2).

The direct operating costs at the mine are estimated to be an average $5.43/tonne on a levelized basis (see Appendix 6-2). The initial operating costs would be $4.7438/tonne in year 1. This figure incudes the labour, operating cost of all equipment in the mine, all fuel and spare parts.

This price, for a 5:1 initial strip ratio and a 7.57 ratio with 40% re-handle equates to a mine ratio of about 7 bcm/trc without re-handle. If the mine productivity is lower, say at 1 megatonne/year or less, the study assumes the mine would utilize low ratio subcrop coal in the early years during low level production, and costs would remain relatively stable. This hypothesis is supported by TAU data from their Isle Lake Deposit studies (Table 3.4).

Table 3.4

Isle Lake Coal Production Costs

Production Level (Kilotonnes/year)	Mine Ratio (bcm/trc)	Cost ($/tonne)
500	3.66	$9.38
1000	4.77	$9.06
1500	6.35	$8.70

Coal load out costs are a part of the ultimate cost of coal. At the 2 million tonne/year level a load out capital cost of $3.5 million is included in the capital costs. This charge is considered adequate whether the coal is transported by rail, truck or slurry pipeline. The load-out operating costs are not expected to vary much with mode of transport and are estimated to be $0.60/tonne.

All of the above capital and operating cost data were entered into the Hampshire Developments Ltd., Project Cost of Service (PCOS) program to determine a sale price of coal (capital service charges included). The result indicates that $12.35 is a reasonable price at 7bcm/trc. in order to calculate the cost of coal at alternate mine ratios, the 0.6 power factor was used. The resultant curve is shown on Fig. 3. .

Delivered cost of coal data was requested from the major mining companies. This data is also plotted on Fig. 3.2 and indicates good agreement with the determined cost of coal.

3.5 Electricity

Electricity is in plentiful supply in Alberta and supply additions can readily be implemented from several existing sources and there are many choices of new energy supply points. Alberta Power has indicated that large scale electric demand would be designed, constructed, maintained and owned by the utility who controls the particular area. Based upon the contracted load, the capital construction costs would be about $1,300,000 for a 7 MW facility down to no cost for a 17 MW facility. The annual operating costs are shown in table 3.5.

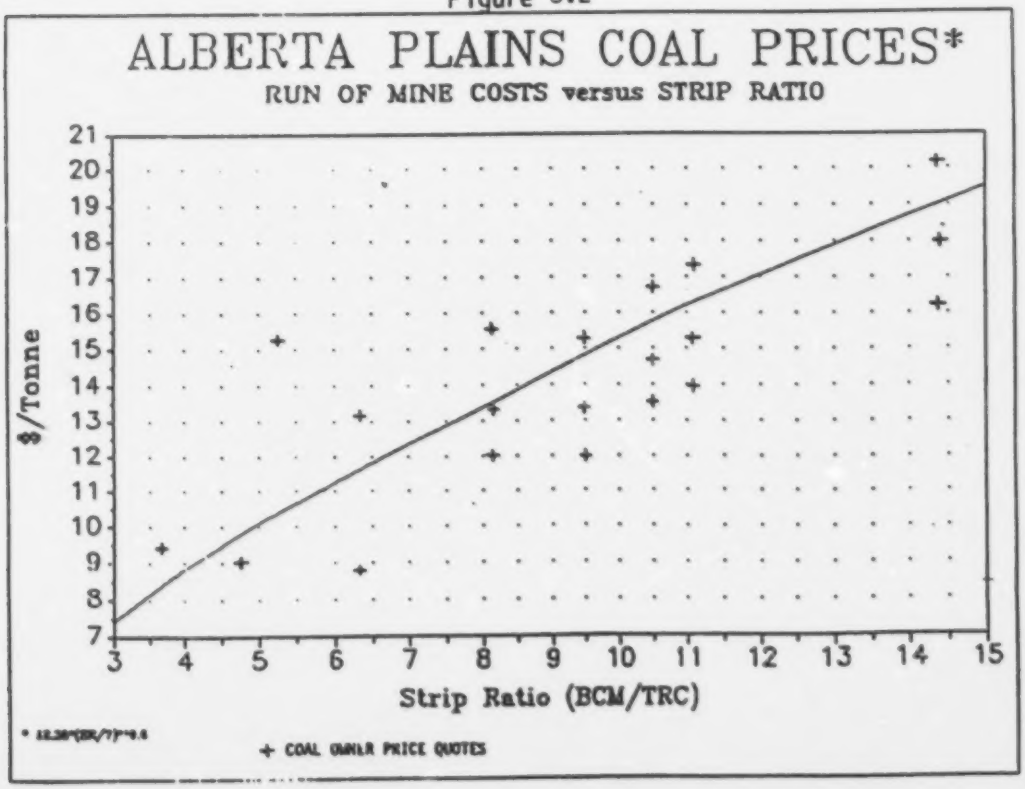
Table 3.5

Annual Electrical Operating Cost (in $x1000)

Contracted Load	7 MW	11 MW	17 MW
Firm Rate	$1,177	$1,813	$2,767
Interruptible Rate	$1,056	$1,659	$2,564
Standby Rate	$ 804	$1,264	$1,954

TransAlta Utilities examined the use of electricity for steam generation. They report that the electrical steam generator was eliminated as these units are only manufactured at pressure up to 600 psig. In the size range required of 190 GJ/hr units, electrical steam generators are the electrode type and the penetration of the electrode through the boiler shell is the limiting factor. Accordingly, electricity is not considered further in this study.

Figure 3.2



4.0 FUEL TRANSPORTATION

4.1 Natural Gas

The study assumes that natural gas is delivered to the lease site with pipeline costs included in the base purchase price. A natural gas site distribution capital cost of $5000/million m^3 of gas consumed was assumed with an annual operating cost of 0.5% of the capital cost.

4.2 Solid Fuels

4.2.1 Introduction

There are three methods in use in North America for transport of solid fuels from the mine gate to demand site, truck, rail and slurry pipeline. All three modes of transport have been evaluated in this study in some detail such that capital and operating costs are estimated for logical tonnages and distances. Existing road and rail networks can be utilized with some upgrading and extension whereas slurry pipeline transport requires significant capital expenditure initially to provide the system. Slurry pipeline does offer lower operating expenses over the project life at certain transport volumes because of more direct routing and lower operating costs.

4.2.2 Truck Transport

Technical and cost information with respect to truck transport of coal in Alberta were obtained from discussions with Trimac and Kleysen Transport. The favoured truck-trailer design for haulage were end-dump trains and B-trains with flatbeds. The operating costs for end dump trains is slightly higher but is offset by the cost of an off-loading tilt table or equivalent. Rather than utilizing specific mines sites, a range of rates applicable to coal movement were developed for a range of distances and

annual tonnage levels.

The quote provided by Kleysen Transport was based on the following assumptions:

i) January, 1985 dollars
ii) 3 year re-newable contract
iii) GVW maximum allowable is 53182 kg,
iv) The optimal truck load is 36.25 tonnes,
v) The shortest practical haulage distance is used,
vi) Average speed is 75 kph, and
vii) Haulage assumed to be 24 hr/day, 7 day/week.

Kleysen provided the following table to exhibit the required rolling stock.

Table 4.1

Coal Haulage Truck Requirements

	0.25 Mt/y	0.5 Mt/y	1.0 Mt/y	1.5 Mt/y
Truck loads/yr	6,896	13,792	27,584	41,376
Truck loads/week	133	266	532	798
# Trucks for 1-way haulage				
-200km	7	13+1 spare	26+2 spare	38+3 spare
250km	7	13+1	26+2	38+3
275km	8	13+1	26+2	38+3
350km	9+1	18+2	35+3	53+4

Truck fleet size numbers in excess of 15 vehicles are considered logistically impractical. Accordingly, truck transport has been considered for movements of up to one-half million tonnes at the quoted distances.

Kleysen indicated an optimal price could be negotiated for such high tonnage hauls under contractual agreement. The quoted price $0.055/tonne-km would be appropriate for either B-trains or flat decks, although flat decks may cost marginally more.

Trimac Consulting Services provided a reasonably detailed set of cost estimates. Their assumptions included:

i) 1985 dollars
ii) Haulage 24hr/day, 355 days/year
iii) One-half hour each for onload/offload
iv) A 5 year contract
v) 53.635 tonnes allowable GVW
vi) Optimal payload of 35.8 tonnes
vii) Road bans are not taken into consideration

The tabulated results of the Trimac haulage estimates is shown on Table 4.2

Table 4.2

Trimac Truck Haulage Costs

Annual Haulage Rate Tonnes/year	Rate for Coal Haulage 245 km ¢/t-km	274 km ¢/t-km	370 km ¢/t-km
150,000	5.22	5.30	5.06
300,000	5.17	5.16	5.03
450,000	5.07	5.11	5.01
600,000	5.05	5.06	4.99
750,000	5.04	5.04	4.98
900,000	5.02	5.01	4.97
1,200,000	4.94	5.01	4.94

Several points are immediately obvious. Although higher tonnages and longer distances favour lower rates, there is no great cost difference between the short distance/low rate haulage than for the long distance/high rate haulage. There are no substantial economies of scale. These estimates are quoted to an accuracy of ±5% based upon the above assumptions.

For purposes of coal and coke haulage in this study, the detailed costs presented by Trimac are modified upward to include:

5% increase for haulage during road bans
5% for socio-economic constraints
10% for variations in demand volumes
20% Total = 1¢/t-km increase

Accordingly, the haulage rates used are shown on Table 4.3.

Table 4.3

Truck Haulage Rates

Annual Tonnage (kilotonnes)	Haulage Rate ¢/t-km
150	6.30
300	6.15
450	6.11
600	6.06
750	6.04
900	6.01
1200	6.01

The haulage distances from the selected mine sites to the steam injection sites were measured on a map. New road requirements to the mine are added separately where necessary to provide capital costs for NEW ROAD at an estimated cost of $300,000/km. This capital cost is factored into the truck haulage rate on a cost of service basis over the life of the project.

Table 4.4

Road Transportation Summary

COAL DEPOSIT	DESTINATION			
	LINDBERGH	PEACE RIVER	CENTRAL ATHABASCA	COLD LK.
Morinville Total	241.3	484.7	334.7	293.8
existing road	230 km	475 km	325 km	280
addition @ mine	4.8	4.8	4.8	4.8
addition @ terminal	6.5	4.8	4.8	4.8
Barrhead Total	306.5	399.8	304.8	
existing	300	395	300	
addition @ mine	0.0	0.0	0.0	
addition @ terminal	6.5	4.8	4.8	
Camrose-Ryley Total	213.0			
existing	200			
addition @ mine	6.5			
addition @ terminal	6.5			
Genesee Total	336.5			
existing	330			
addition @ mine	0.0			
addition @ terminal	6.5			
Isle Lake Total	329.6	439.5		
existing	315	425		
addition @ mine	8.1	9.7		
addition @ terminal	6.5	4.8		
Thorhild Total	221.5		284.8	234.0
existing	215		280	225
addition @ mine	0.0		0.0	0.0
addition @ terminal	6.5		4.8	9.0
Fox Creek Total		261.3		
existing		237.5		
addition @ mine		19.0		
addition @ terminal		4.8		
Clear Hills Total		208.0		
existing		134.4		
addition @ mine		68.8		
addition @ terminal		4.8		

4.2.3 Rail Transportation

Rail transport charges were determined using data from three main sources, the Market Planning and Development Division of CN Rail, a compilation of 1984 car-lot haulage rates for coal movements in B.C. and Saskatchewan, and 1985 Unit Train Rates for all coal shipments to the Canadian West Coast.

Car Lot Shipments

The four car-lot shipments included in the data include modest tonnages (40,000 t/y to 300,000 t/y and haulage distances of 250 to 600 km. The rates vary from $0.02745/t-km to $0.04308/t-km and average $0.0375/t-km, which, when inflated to 1985 dollars at 4%, equals $0.0390/t-km.

Table 4.5

Coal Unit Train Rates to West Coast Ports (1985)

From	Distance km	Tonnage t/yr	Cost $/t	Rate $/t-km
Gregg River	1130	750,000	23.41	0.0208
Luscar Sterco	1095	410,000	21.09	0.0192
Byron Creek	1125	<1,000,000	23.86	0.0212
Westar	1160	1,000,000	23.10	0.0199
Smokey River	1100	<1,000,000	19.12	0.0174
			Average:	0.0197
CNRL	1130	+1,000,000	23.47	0.0208
Westar	1120	6,000,000	20.76	0.0185
Fording	1170	3,400,000	21.68	0.0185
Luscar	1120	2,250,000	21.09	0.0188
			Average:	0.0192

Both sets of data indicate that although the freight rates can be sensitive both to tonnage hauled and to distance hauled, the rates in a given category, i.e. car-lot or unit train, do not vary significantly.

Unit Train Shipments

This data received from CN is tabulated in Table 4.6. This data suggests that rail rates in Alberta are not particularly sensitive to haulage distance but rather more to tonnage hauled. Unit train rates appear to be about 70% of car lot rates in the CN data, however the other data sets indicate unit train rates to be less than 50% of car-lot rates. Compared to the other data sets, however, the quoted CN rates are much higher, up to 400% higher for unit train rates and up to 260% for car-lot rates as compared to the other data sets.

The haulage distances for coal in this study vary from 200 km to 620 km and average about 390 km. This is about one-half of the distance as compared to the unit train cost presented in table 4.5, but similar to the car-lot rates in the documented data. Railbed capacity to Peace River and Lloydminster is at maximum required for unit trains, therefore the rates on these lines should be similar to those documented elsewhere in the country. Accordingly the CN quoted rates are not considered entirely valid for this study.

Table 4.6

CN Rail Estimate for Coal Shipments*

From	To	Distance km	Car Lot Shipments Costs $	Car Lot Shipments $/t-km	Unit Train Shipments Cost $	Unit Train Shipments $/t-km
Morinville	Peace River	455	27.55	0.0605	18.18	0.0400
Barrhead	Peace River	510	27.55	0.0540	18.18	0.0356
Wabamun	Peace River	620	29.20	0.0471	18.73	0.0302
				0.0539		0.0353
Morinville	Ft. McM.	455	28.10	0.0618	19.29	0.0424
Barrhead	Ft. McM.	500	29.20	0.0584	19.84	
Thorhild	Ft. Mcm.	368	27.00	0.0734	18.73	0.0509
				0.0645		0.0506
Morinville	Lindbergh	240	25.35	0.1056	17.63	0.0735
Barrhead	Lindbergh	283	27.00	0.0954	18.73	0.0662
Forestburg	Lindbergh	350	27.00	0.0771	18.73	0.0535
Wabamun	Lindbergh	303	25.90	0.0855	18.18	0.0600
Thorhild	Lindbergh	204	25.90	0.1270	18.18	0.0891
				0.0981		0.0685

* Source: CN Rail, Edmonton

Table 4.7

Connecting Distances - Existing Rail
(Km)

	Lindbergh	Cold Lake	Peace River	C.Athabasca	N. Athabasca
Morinville	211.2	255.0	402.2	-397.4	-460.0
Barrhead	244.4		452.2	-432.8	
Camrose	240.6	340.0		-487.5	537.5
Genesee	264.3				
Isle Lake	272.6	350.0	570.4	-487.5	-537.5
Thorhild	189.2	210.0		-314.8	-364.8
Fox Creek			120.0		
Clear Hills			0.0		
Halkirk	475.0				
L. Slave Lake					
Tar Island			-900.0	50.0	0.0
Mildred Lake				50.0	0.0
Lloydminster	85.6	200.0			

Table 4.8

Connecting Distances - New Rail
(Km)

	Lindbergh	Cold Lake	Peace River	C.Athabasca	N.Athabasca
Morinville	28.8	25.0	52.8	57.6	60.0
Barrhead	38.4		57.6	67.2	
Camrose	24.4	25.0		50.0	62.5
Genesee	36.4				
Isle Lake	30.4	41.0	49.6	56.3	72.0
Thorhild	14.8	25.0		53.2	62.5
Heatburg	22.4				
Fox Creek			132.0		
Clear Hills			125.0		
Halkirk	22.4				
L. Slave Lake					
Tar Sands			0.0	82.0	65.0
Mildred Lake				88.0	65.0
Lloydminster	22.4	50.0			

Rail Rates Used in Fuel Options

In this study the assumption is made that annual tonnages equal to, or less than 0.5 megatonnes have been assigned car-lot rates, and tonnages larger than 0.5 megatonnes/year use unit train rates. Haulage on lines with unit train capability such as to Peace River and Lloydminster include an assumed price increase of 8% from those shown on Table 4.5 and the calculated average car-lot rate to compensate for shorter rail hauls, increased load and unload time and required flexibility in demand levels.

The lines to the Athabasca areas and to Cold Lake can haul only 73 tonne loads and, accordingly, an additional 25% rate is added to coal haulage rates to these areas. The resultant haulage rates are shown on Table 4.9.

Table 4.9

RAIL RATES*
Solid Fuels

Mode:	Annual Kilotonnes	Lindbergh & Peace River	Cold Lake & Athabasca
		($/tonne-km)	
Car-Lot	100	0.0607	0.0657
	200	0.0515	0.0565
	300	0.0458	0.0508
	400	0.0423	0.0473
	500	0.0402	0.0452
Unit-Train	> 500	0.0310	0.0360
	600	0.0289	0.0339
	800	0.0260	0.0310
	1000	0.0242	0.0292
	1500	0.0221	0.0271

NOTE: (1) Based on current 1985/86 rates +8%
(2) Upgrading costs of $0.005/tonne-km assumed for Cold Lake & Athabasca.

4.2.4 Slurry Pipeline Transport

Transport of coal by a slurry pipeline is relatively novel, with only one commercial scale system operating in North America. This example, the Black Mesa Pipeline in Arizona/Nevada, consists of 440 km (273 mi) of mostly 457 mm (18") pipeline which has a transporting capacity of 4.9×10^6 tonnes per year. At this level of operation, the Black Mesa Pipeline exceeds by a factor of at least 3 the maximum requirements of the current study. Built in 1970, it now has 15 years of operational experience.

In 1980, CANMET sent several individuals to observe the Black Mesa Pipeline operation. In the report filed as a result of this visit, Mr. D.L. Fryer (engineer, Plant Engineering Group, Southern California Edison Company (SCE) indicated that for distances in the order of 500 km (300 miles), coal pipeline transport is considered to be more reliable than rail transport based on a comparison of the SCE operation associated with the Black Mesa Pipeline and 22 other SCE facilities all serviced by rail delivered coal. SCE also claimed that pipeline transport of coal is lower cost than by railway and constitutes a much better protected investment against inflation in the long run. The only problems encountered with the Black mesa Pipeline involved line plugs which formed during shut downs in the early stages of the operation when tests utilizing coal coarser than design size consist had been attempted. The shutdowns were coincident with power failures. It would appear therefore, that size consist is critical to the successful operation of a slurry pipeline. Black Mesa Pipeline staff noted this in the Proceedings of the Fifth International Technical Conference on Slurry Transportation. They gave the size consist in Table 4.10 and noted that fines content is critical.

TABLE 4.10

Black Mesa Coal Slurry Size Consist

Tyler Mesh	% Retained
+14 (1.19 mm)	1.5
+20 (840 um)	4.0
+28 (590 um)	11.0
+48 (297 um)	32.5
+100 (149 um)	55.0
-325 (44 um)	(19.5) passing

At the generating station where dewatering of the coal is required, a larger fine fraction results in greater surface area and hence increased dewatering difficulty.

Singleton Associated Engineering Ltd. (SAEL), provided data on the cost of slurry coal transport to the heavy oil sites at a final rate of 1.628 megatonnes/year. At this volume, the resultant tariffs and cost per unit distance suggested that pipeline transport could be viable. Therefore, SAEL were requested to provide a pipeline transport cost analysis based on additional assumptions. However, no clear relationship between costs per tonne-kilometer and annual coal tonnages are apparent from these first results.

i) initial coal slurry mixing excluded from transport charges (capital and operating costs included in mine cost).
ii) de-slurrying at demand site excluded (these capital and operating costs are included in site facilities).
iii) a single haulage distance of 250 km pipeline length, 75 km water supply line.
iv) pipeline is owned and operated on a cost of service basis by a third party.
v) tariffs were to be estimated for range of volumes, specifically; 360,000 to 450,000 tonnes/yr.
450,000 to 600,000 tonnes/yr.
720,000 to 900,000 tonnes/yr.
950,000 to 1,200,000 tonnes/yr.

TABLE 4.11

1.6 Megatonne Slurry Pipeline Economics

Coal Source	Demand Site	Pipe Length (km)	Delivered Coal Cost $/Tonne	Delivered Coal Cost $/Tonne.km
Camrose-Ryley	Lindbergh	150	$ 7.99	$0.03549
Morinville	Athabasca	350	$13.72	$0.03430
Judy Creek	Peace River	260	$13.72	$0.05276

The second set of results, following the new assumptions, are shown in Table 4.12.

Table 4.12

Slurry Pipeline Tariffs Design Throughput Dependence

Throughput (Tonnes/Year):				
Minimum	950	720	470	360
Maximum	1200	900	600	450
Tariff (at Maximum:)				
$/Tonne	12.33	15.40	21.43	29.93
$/Tonne Kilometer	0.0493	0.0616	0.0857	0.1197

A log-Linear regression analysis was then performed upon these rate-volume relationships to obtain the exponential pipeline transportation rate parameters used in this study. Such an approach glosses over variations such as terrain, water supplyline length, and level of operation, but brings consistency and simplicity to the analysis. Both the capital and operating costs, used to derive the above tariffs, were deliberately estimated on the high side. Therefore, the tariffs used in this study are considered to be conservatively high.

As a consequence of this simplified slurry pipeline tariff-estimating approach, only coal tonnages and transport distances need to be specified in order to calculate slurry pipeline transportation costs. The "straight-line" distances

used in this study are summarized in Table 4.12. The analysis program (FUELOPTS) automatically adds 5% to these distances to accommodate vertical and horizontal deviations from strict linearity.

Table 4.13

Connecting Distances - Pipeline
(Km)

	Lindbergh	Cold Lake	Peace River	C.Athabasca	N.Athabasca
Morinville	195.0	225.0	345.0	290.0	395.0
Barrhead	240.0		310.0	290.0	
Camrose	130.0	210.0		350.0	455.0
Genesee	240.0				
Isle lake	265.0	300.0	365.0	355.0	460.0
Thorhild	150.0	175.0		245.0	350.0
Heatburg	225.0				
Fox Creek			200.0		
Clear Hills			125.0		
Halkirk	190.0				
L. Slave Lake					
Tar Island				50.0	37.5
Mildred Lake				50.0	37.5
Lloydminster	75.0	150.0			

Coke is not considered a suitable fuel to be subjected to slurry transport.

5.0 STEAM RAISING TECHNOLOGY FOR EOR

5.1 General

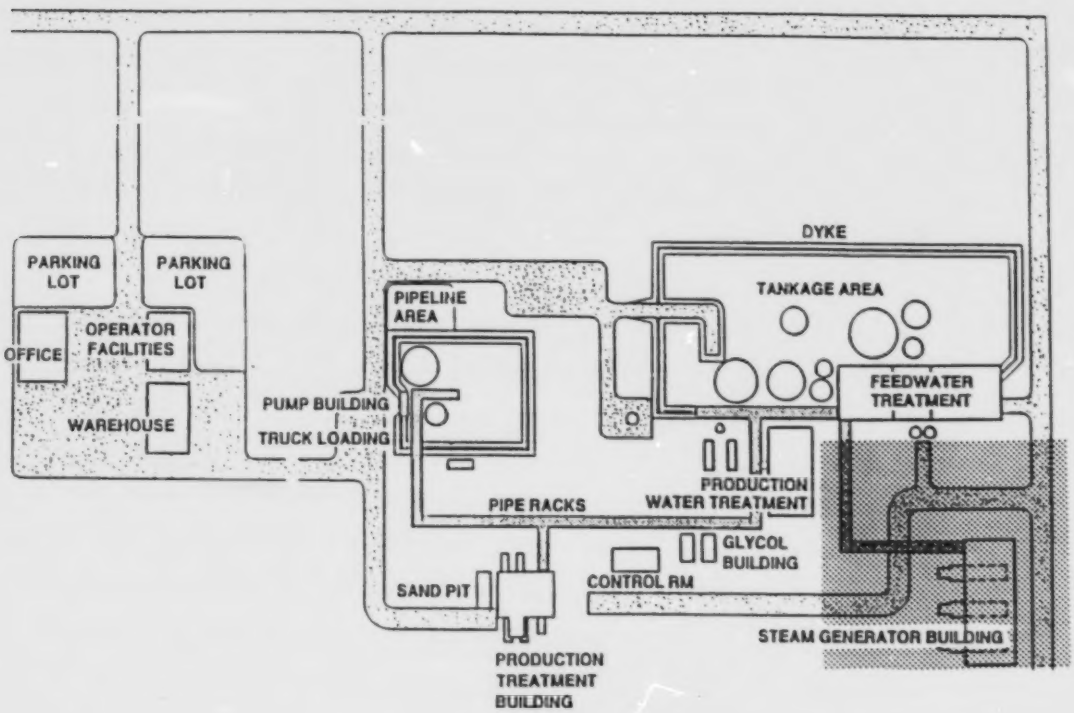
Steam is important in many industries and there are numerous methods and technologies available to raise steam. Many fuels can provide the feedstock energy including oil, natural gas, coal, coke, and upgrader by-products as well as wood chips and biomass. In the heavy oil fields, however, natural gas and produced oil have been used almost exclusively to provide the energy to raise steam for injection into the reservoirs. There has, however, been a modest interest in coal and petroleum coke firing using fluidized bed combustion technology in the U.S. and Venezuela.

In the U.S., in particular the heavy oil and tarsand fields of California and Texas, the standard equipment for steam raising is the 50 mmBTU/hr (53 GJ/hr) oilfield steam generator. This unit is capable of firing with either oil or natural gas. The unit is designed at this particular size in order to be shop erected and to meet the state road weight and size limitations. Although inefficient in concept, oil producers purchase large numbers of units and install them in parallel rows with each unit feeding steam into the central steam line for distribution to the injection wells.

Coke firing of a Fluidized Bed Unit (FBC) at the Conoco facility in the Orinoco Field of Venezuela has been studied with positive recommendations. In addition, two 53 GJ/hr (50 mmBTU/hr) units have been installed in the San Antonio Field in West Texas at a Conoco site and on the Texas Tarsands Project. These units were installed as commercial scale projects but have been also used as research and Development facilities for testing alternate fuels.

Figure 5.1

Steam Generation Equipment Included In Study*



* N.B. Steam generation equipment not indicated within the shaded portion of the diagram is "standard" irrespective of fuel choice and therefore is not considered in this study.

In Canada, more liberal road regulations allow for much larger loads as well as overweight permits when required. During initial planning of the Esso Cold Lake Project, the steam generator manufacturers scaled up existing gas fired steam generators to as large as 190 GJ/hr (180 mmBTU/hr) and these are now one of the standard units used in Canada. The units are prefabricated in two or three components that are erected on site.

5.2 Steam Specifications

Volumetric steam requirements for heavy oil and tarsand recovery operations in Canada vary significantly but pressures tend to lie in the range of 11,030 Kpa (1600 psi) to 17,200 Kpa (2500 psi) at 80% quality "wet steam". Due to the use of lower quality feedwater, most projects require the 80% quality steam (i.e. 80% saturated steam, 20% water) in order to prevent scale formation in the generator tubes. Generally, the design criteria of the steam production facilities are strongly influenced by feedwater quality, injection pressures, steam production reliability requirements, and general project flexibility requirements.

Injection pressures presently used in Alberta vary from 11,030 Kpa to 17,200 Kpa (1600 to 2500 psig). Because injection pressures are a function of depth of reservoir burial, local stratigraphy, formation pressures, and other factors, a substantial amount of research is required for determining the correct pressure for a given property.

The calculation of the energy requirements to raise a specified quantity of steam can be carried out using saturated steam tables such as listed in Combustion, Appendix F, Steam Tables. The following example serves to illustrate:

Enthalpy of steam = h_g
Discharge Pressure (psia) = p, Quality of steam = s
Enthalpy of water = h_f (at steam temp.)
Enthalpy Gain = Enthalpy Steam + Enthalpy Feedwater
Enthalpy steam = $(h_f) + (s \times h_g)$
Enthalpy feedwater = h_f (at initial temp.)
Energy requirements/lb = H

Example:

Initial Feedwater Temp = 158°F
Required pressure = 1700 psig
Steam Quality = 80%
Heat Gain = 636 + (0.8 x 522.2) = 1054.3
Less Enthalpy of feedwater = 126.0
Total heat Gain = 928.3 BTU/lb
= 2.155 GJ/m^3

5.3 Feed Water Quality

Wet steam production allows the use of lower-quality feedwater than that required for 100% or superheated steam operations, nevertheless some water treatment is still essential. Low quality water can cause generator scaling, such that acidizing is required to remove the scale and prevent tube failure. The water source dictates the type of treatment required. Two sources of water are available.

Surface water. Surface water may be obtained from either rivers or lakes. River water usually contains mud or silt and dissolved minerals and gases. Lake water generally contains dissolved minerals and gases. Water from these sources requires filtering to remove the silts and to prevent fouling of the resin bed in the water softener.

Ground water. Producing oil wells yield formation water that has been filtered through the reservoir rock which reduces the suspended material. It usually has a high dissolved mineral content, with total dissolved solids (TDS) commonly reaching 20,000 ppm or more.

Filters are used to remove suspended material prior to treating the water in ion-exchange equipment for removal of dissolved mineral matter. Cartridge or sand filters are used when there is no oil in the water. When oil is present, flotation or other oil removal systems are usually installed upstream of the filters. A diatomite filter also is very effective in removing small quantities of oil.

Calcium and magnesium ions are the cause of what is known as "permanent hardness" (scale causing) and must be eliminated. Ion exchange beds are used to achieve very low hardness. The softened water is treated with additional chemicals to further prevent scaling in the

boiler tubes. Polymers, phosphonates, and polyphosphates prevent calcium carbonate deposition on the tube walls. Ionic compounds (other than calcium and magnesium) in reasonable quanitites present few problems when generating wet steam because they remain dissolved in the water phase and are swept out with the steam. The water also must be free of corrosive or oxidizing gases, such as oxygen and carbon dioxide. Sodium sulfite is used for oxygen scavenging. Approximately 8 ppm of sodium sulfite is required to scavenge 1 ppm of oxygen. Excess sodium sulfite is maintained in the generator. Morpholine or another filming amine can be added to prevent corrosion. For most steam injection processes, the feedwater can be used satisfactorily with near zero hardness at temperatures of 15°C to 105°C containing up to 8,000 ppm TDS.

5.4 Steam Production Equipment

5.4.1 General

In the heavy oil fields there are basically two types of steam generation equipment currently in use for the steam injection projects but there are potentially five types that could be used:

i) oil or gas fired once-through, forced-circulation, forced draft type steam generator,
ii) fluidized bed combustion steam generator (atmospheric, circulating bed or pressurized),
iii) pulverized coal fired boilers. The Esso Cold Lake Project carried out initial R & D on the concept using fresh water in the boilers. The produced steam was superheated and mixed with partially cleaned produced water to achieve 80% quality injection steam.
iv) pulverized coal fired, once through, steam generator
v) the electrical steam generator (with restrictions)

The equipment included in the "on site" steam raising capital and operating costs is highlighted on Figure 5.1, a drawing showing

Central Facilities Layout for the Aberfeldy Steamflood Project. The highlighted equipment includes: Steam generators, feedwater pumps, blowdown tank and air compressors, steam piping and electrical wiring, instrumentation, precipitation and de-sulphurization equipment, fuel handling, ash handling and disposal. Allowance has also been made for the cost of the buildings, insulation, paint and landscaping.

5.4.2 Gas Fired Steam Generators

Steam generators were first used in oil recovery operations in the 1960s. Oil-field applications require large quantities of water because all the steam is injected into the formation and none is recirculated as in a power plant. Today, most steam injection thermal recovery projects use a steam generator instead of a boiler. The generator is a once-through or single-pass water-tube boiler. The feedwater pump pressures the water to the required level and forces it through the piping where it is heated and vaporized. Approximately 80 wt% of the feedwater is converted to steam leaving 20% as liquid to carry off dissolved solids and to prevent solid deposits forming on the tube walls. Solid deposits insulate the tube and thereby reduce heat transfer through the metal wall causing hot spots and possible tube rupture. Therefore, the feedwater is decreased to zero hardness, but the total dissolved solids can remain relatively high if the liquid water phase is sufficiently large to keep the solids in solution.

Steam generators for oil-field application range in size from 12 to 190 GJ/hr. A 190 GJ/hr unit can generate approximately 1800 m^3 of 80% quality steam/day and is suitable for large-scale, multi-well projects. A 12 GJ/hr unit delivers about 120 m^3/day steam and, being readily portable, is suitable for single-well treatments.

Figures 5.2 and 5.3 shows a typical steam generator using straight tubes, has radiant and convection sections, and has a

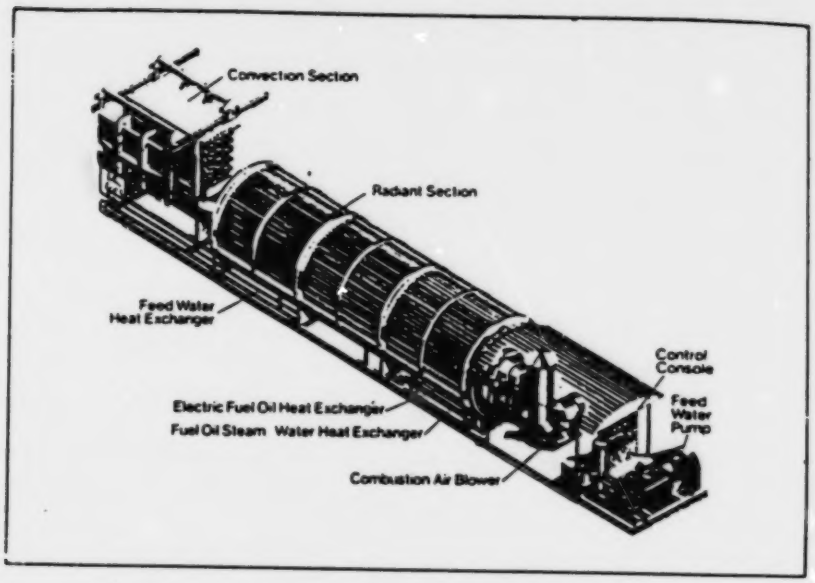
feedwater heat exchanger. Most generators in Alberta are now equipped with only gas burners. Water enters the system through the feedwater pump and then passes through the heat exchanger where it is heated to approximately 200°F. This preheat is necessary to prevent external tube corrosion in the convection section where heat is scavenged from the flue gas. The feedwater preheat maintains the tubes in the convection section above the dew point of the flue gases.

The convection section contains both bare and finned tubes. The bare tubes are contacted first by the high-temperature combustion gases, which reduce the temperature of the gases prior to contacting the finned tubes. This reduction decreases high temperature corrosion and solids buildup on the finned tubes and extends the tube life. The feedwater flow is countercurrent to the gas to improve heat exchange efficiency.

The gas flow in the convection section is determined by the size and shape of the unit. Currently, a pyramid shape is sometimes used to both increase gas velocity and to reduce fouling the tubes. Pressure drops must be kept to a minimum in this section to maintain combustion efficiency.

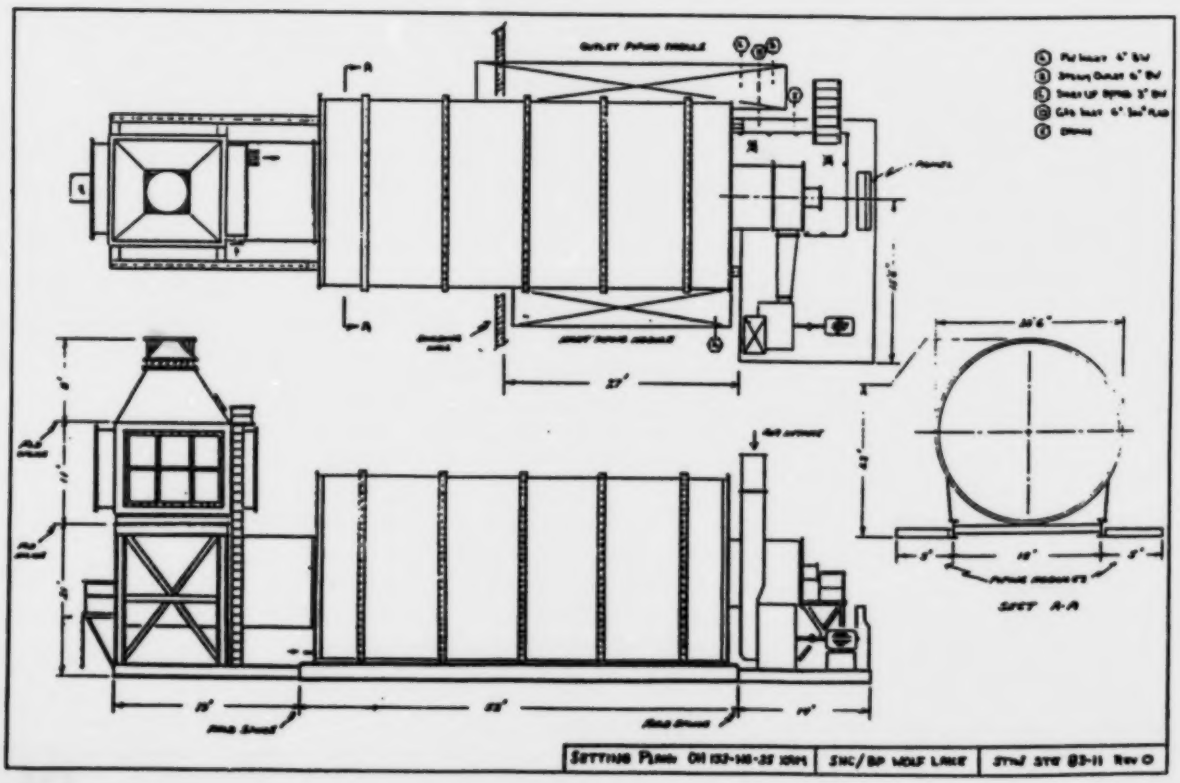
The heated water leaves the convection section and passes through the feedwater heat exchange to warm the incoming cold water. It then flows to the radiant section, where the tubes are exposed to the flame. There it is converted to steam by radiant heating. The steam then enters the steam distribution system for injection at the wells being treated.

Fig. 5.2
GAS FIRED STEAM GENERATOR DESIGN



(courtesy C-E Natco)

Fig. 5.3
DIMENSIONS OF GAS 190



Capital Cost

Capital costs of gas (or oil) fired steam generators are provided on the next page as determined by the study group with data from TAU. Capital costs were estimated for a seven unit setup and scaled down to a 5 unit project size. From this data, L.A. Smith Consulting & Development, Ltd. scaled the costs to relate to varying project sizes.

Table 5.1

Gas Generator Capital Cost Breakdown
Based on 5 Unit Project

Item	Cost ($ x 1000)
Steam generators (5)*	7,000
Feedwater pumps	700
Compressors & blow down tanks	240
Steam pipelines	2,800
Electrical & instrumentation	1,700
Building ** and insulation	2,700
paint and landscape	460
	$15,600

* price includes assembly on site

** The building contains the control panel, the gas firing unit and just over half of radiant section. The remainder of radiant section, and the convective section located outside the building (see Fig. 5.3).

Based upon a cost multiplier index of 0.86 for scaling, the price of the 190 GJ/hr units are estimated to be:

Number	Installed Price ($ x 1000)
1	3,900
2	7,100
3	10,000
4	12,850
5	15,600
10	28,250
20	51,280

Operating Costs (Fuel excluded)

Operating costs were estimated for a wide variety of production levels by Monenco. Based upon the 7 unit installation and scaling to other case sizes, the following data were used for input:

Electricity - Estimates of electric demand were provided by CH_2M Hill and the electric charge rate was estimated to be about $0.04/kwh by Alberta Power Ltd.

Water - a cost common to all combustion techniques. Excluded.

Operators - estimated in thousands of man-hours per year at $25/man-hour wage rate.

Maintenance - as estimated by Monenco.

Chemicals - not included as part of this study.

Table 5.2

Gas Fired Steam Generator
Annual Operating Cost Summary

Number of Units	Electricity 10^6 Kwh	Electricity $\$x10^3$	Operators Men	Operators $\$x10^3$	Maintenance $\$x10^3$	Total $\$x10^3$	% of Capital
1	3.6	195	4.5	214	274	683	17.5
2	7.2	363	7.8	365	415	1143	16.2
4	14.4	677	13.2	622	629	1928	15.0
5	18.0	828	15.7	739	719	2286	14.7
10	36.0	1545	26.8	1260	1090	3895	13.8

Based upon a percentage of capital costs, the operating costs decreased from 17.5% (single unit) to 13.8% (10 units).

Suppliers

There are several potential suppliers of the gas/oil fired 190 GJ/hr steam generators in Canada. They are:

Canadian Boilers Limited, Mississauga, Ontario

C.E. Natco, Calgary, Alberta

Dominion Bridge, Calgary, Alberta

Thermotics Inc., Edmonton, Alberta

Struthers TIW. Ltd., Calgary, Alberta

Advantages:

Small in size and easily transported
Pre-fabricated in shop into simply joined units.
Inexpensive to build.
Flue gas clean-up not necessary.

Fuel handling and operation is very simple.
Very high turndown capability.
Capable of using produced water with high TDS content.
No ash handling requirements.
Proven in numerous field applications.

Disadvantages:

Uses a very high quality form of energy as fuel.
Fuel cost is commonly very high.
Natural gas availability may be restricted at some time in the future.

5.4.3 Fluidized Bed Combustion (FBC)

General

Fluidized Bed Combustion systems are capable of efficiently burning a wide range of low cost fuels in an environmentally acceptable manner. Referred to in 1979 by EPRI as "a black box that would solve many of the problems electric Utilities wrestle with - coal is fed into the black box, but few sulphur or nitrogen oxides come out", FBC has shown great promise in recent years. For example:

i) the NCB and Central Electric Generating Board (UK) have launched a $34 million R&D program on pressurized FBC. (PFBC).
ii) European designed Atmospheric Circulating FBC (CFBC) units at heavy industry size are commercially available and several are operating.
iii) in the U.S., Northern States Power and EPRI are retrofitting an 85 MWe power plant to achieve 125 MWe with an Atmospheric FBC (AFBC). Other companies are planning a $200 million 160 MWe commercial scale AFBC plant. In addition, there are several projects considering CFBC or AFBC design installations.

Given the recent increased level of interest, the range of the commercial applications of FBC technology is increasing rapidly and several differing technologies are being developed.

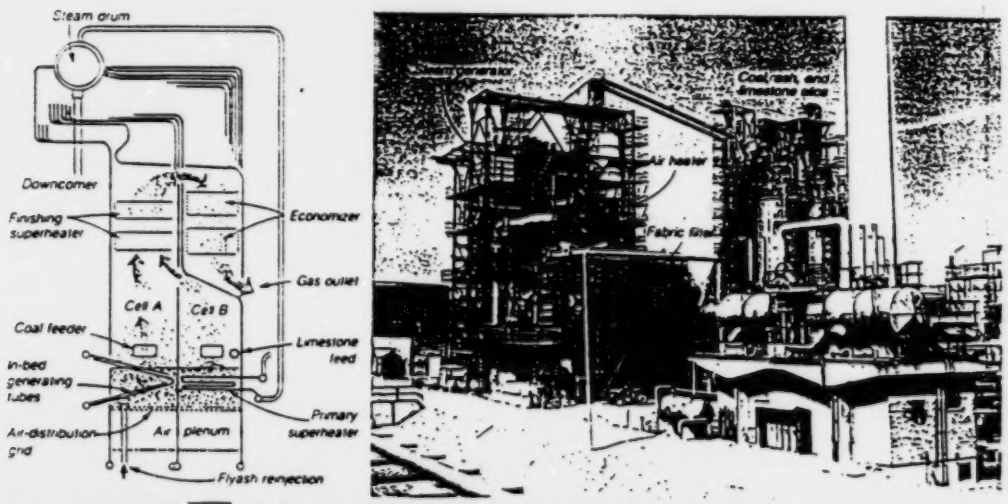
Atmospheric (AFBC)

Bubble Bed AFBC involves the creation of a fluidized bed of non-combustible particles such as sand, coal ash and/or limestone kept in a hot, highly turbulent state by an upflow of feed air

through a distribution system in the base of the bed (see Fig. 5.4 & 5.5). Heat for steam raising can be extracted by means of heat exchange surfaces (tubes) immersed in the bed (in-bed tubes) which take advantage of the extraordinary heat flux rates in the fluidized beds. In addition convection tube banks located in the exhaust gas pathway can also extract a significant amount of heat. Fuel conversion efficiencies are very high and in the case of coal combustion, there is less than 1% C left in the bed.

Figure 5.4

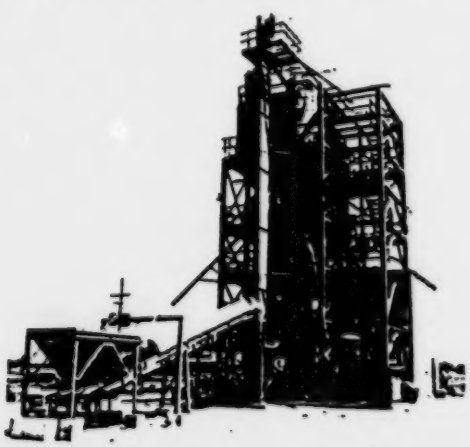
AFBC Unit at Shell Nederland Europort Facility



11-12. Shell Nederland Raffinaderij BV's coal-fired fluidized-bed boiler starts up later this month at the company's Europoort crude-oil storage facility. The two-cell unit will produce 110,000 lb/hr of 1175-psig/925F steam for power and heating

Figure 5.5

FBC50 Unit at South Texas Steam Flood Project



The major advantages of AFBC units are:

i) high emission control with nominal loss of efficiency
ii) very low NO_x emissions
iii) reduced boiler fouling
iv) flexibility in fuel choice and
v) costs are similar to PCF units.

There are numerous AFBC Bubble Bed units in operation worldwide. The Chinese are using over 2000 units (see Appendix 4), many European plants are in operation, several power plants and industrial steam generators use AFBC. A CE Natco 50 mmBTU/hr AFBC unit is in operation for oilfield steam generation in South Texas (Fig. 5.5).

Circulating Fluid Bed Combustion (CFBC)

CFBC boilers typically operate at greater combustion efficiencies and at lower excess-air levels than the bubble bed AFBC steam generators. In addition, these units offer greater flexibility in fuel-feed systems, require less limestone for SO_2 capture and are easily adapted to staged-combustion techniques for NO_x control.

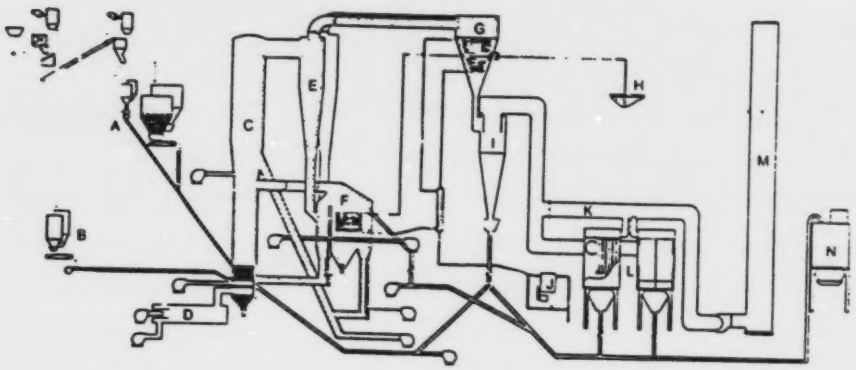
The primary reason for the above advantages of the CFBC over the typical AFBC system is that high fluidizing velocities are a fundamental part of CFBC design to promote solids circulation. Therefore, a smaller feed particle size is necessary. This provides the opportunity of separating the combustion zone from the heat exchange section (see Fig. 5.6 & 5.7). In addition, removal of the in-bed tubes from the combustion zone eliminates the major cause of tube corrosion common to the AFBC units.

Major disadvantages of CFBC (versus bubble bed AFBC) are:

i) increased cost of particulate capture
ii) increased cost of coal and limestone grinding
iii) increased erosion within the combustor, and
iv) lack of available design and operating data.

Figure 5.6

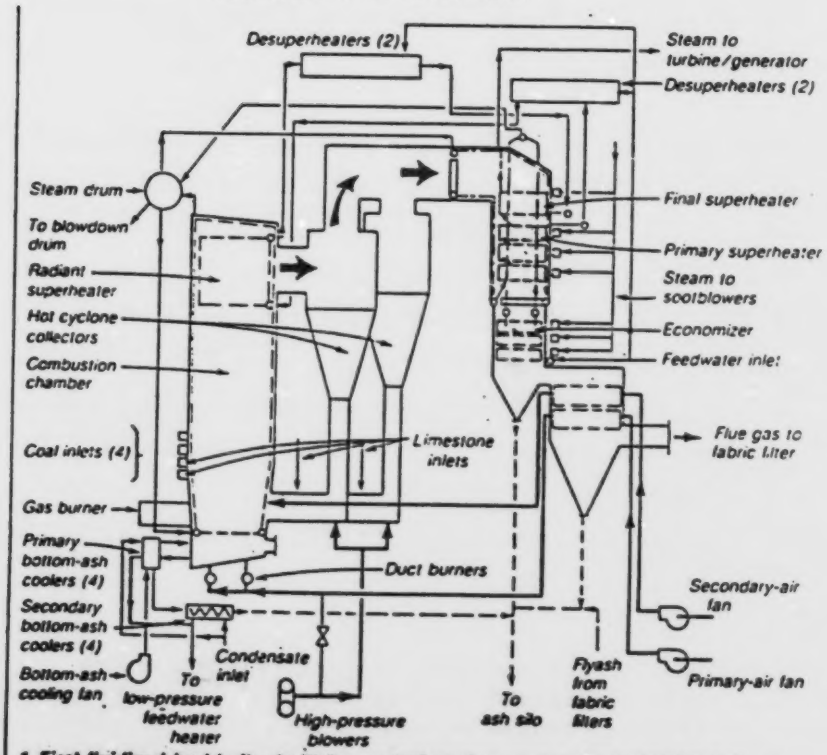
Struthers Thermo-Flood Corp. Multi-Solid Fluidized Bed Combustor



A. Coal/Coke Feeding System
B. Limestone Feeding System
C. Combustor
D. Preheat Combustor
E. Primary Cyclone
F. External Heat Exchanger
G. Convection Section
H. 80% Steam Product to Well
I. Collector Cyclone
J. Feedwater Pump
K. Baghouse By-Pass
L. Baghouses
M. Stack
N. Ash Storage Bin

Figure 5.7

COLORADO UTE CFBC UNIT



1. First fluidized-bed boiler built for central-station service, rated 925,000 lb/hr at 1510 psig/1005F, will be installed by Colorado-Ute Electric Assn Inc

Power, February 1985

There are only a few of these units in operation, most notably a 50 mmBTU/hr Conoco unit in a South Texas tarsands reservoir and a 125 Mwe unit installed by Colorado-Ute Electricity at Nucla, Colo.

Pressurized Fluidized Bed Combustion (PFBC)

PFBC offers the capability to apply direct coal firing to a gas turbine in a combined cycle plant. Since the coal is burned at a lower temperature than in conventional combustion systems, the corrosive constituents are not volatilized into the gas stream and the gas-born particulate matter is less abrasive. Accordingly the system, which operates at elevated pressures, is designed to operate at higher thermal efficiency and have lower capital costs than comparably sized PCF units. Nearly all of the current research carried out at present is centered in Europe.

Capital Costs of FBC Units

The capital costs detailed below have been estimated to be consistant with other combustion technologies and apply to FBC units in general without reference to any specific FBC technology. The costs are estimated for the 530 GJ/hr and the 370 GJ/hr unit from data provided by TransAlta Utilities and Struthers TIW Ltd. The Struthers data provided capital costs and scale up cost factors (for building larger or smaller units). All other capital cost components are estimated from the TAU cost breakdown and from discussion with industry personnel.

Fuel handling on site includes unloading, storage and all handling up to the burner tip. The capital costs include the cost of capital equipment for these purposes. At lower volumes it is anticipated the fuel handling equipment would be based upon one or more front end loaders with a mobile feeder/hopper conveyer system. For large volumes, a live stockpile system would likely be necessary.

Ash disposal for coal and coke are estimated to be $2.1 million for a project size with two FBC 530 units. Although coke has less ash than coal, the higher SO_2 content will require upgraded facilities therefore ash handling capital charges are considered similar for each fuel type.

Table 5.3

Capital Costs
for a
2 Unit FBC 530 Installation

Item	FBC 530 ($x1000)
Steam Raising Equipment	29,600
Feed Pump and Blowdown Tank	740
Air Compressor	740
Steam Piping	6,000
Electrical and Instrument	6,000
Building, Insulation, Paint & Landscaping	7,960
Fuel Handling, Unloading, Storage	8,700
Ash Disposal	1,300
SO_2 Capture*	0
	61,240

* SO_2 Capture is included in economics program if feedstock SO_2 content exceeds emission limits.

To scale down to an FBC 370, the following graph provided by Struthers TIW Ltd. indicates that two FBC 370s should cost 87% of the two FBC 530s or $53,280,000 (Fig 2.8).

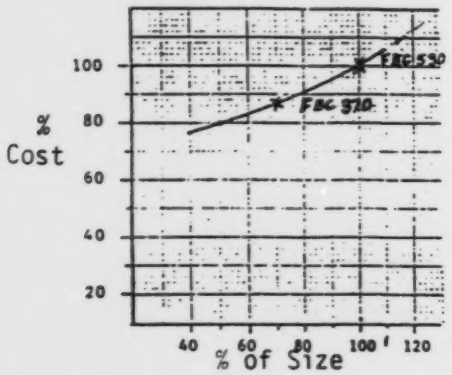
The price multiplier index recommended by Struthers for the FBC units is 0.67. in order to increase or decrease unit numbers, the formula used is:

$$\text{New Price} = \text{Old Price} \times \left(\frac{\text{New Quantity}}{\text{Old Quantity}}\right)^{0.67}$$

This study used a standard 0.67 scale up factor for both FBC and PCF equipment. Using the formula, a single FBC 530 costs $38.5 million and, from Fig 5.8, a single FBC 370 costs $33.1 million.

Figure 5.8

Capital Cost Curve for Scale Change of FBC Units



Operating Costs

Operating costs have been determined from data provided by TAU regarding labor requirements, maintenance costs, and fuel and ash handling costs and from industry discussions on electrical and labour requirements. The electricity demand was determined by CH_2M Hill and the electric charge rate was estimated from data supplied by Alberta Power Limited. The raw data, tabulated below, has been reduced to operating charge as a percentage of the related capital cost. For the FBC 530 unit, annual operating costs are estimated to be 10.25% of total capital costs.

Table 5.4

FBC 530 Operating Costs

Item	Number of Units (cost in $ x 1000) 1	2	4
Electricity @ $0.04/kwh	1,371	2,387	4,156
Labor @ $25/manhour	705	1,202	2,050
Maintenance	1,442	2,186	3,314
Fuel Handling	250	379	574
Ash Handling	50	76	115
	3,818	6,230	10,209
% of Capital Cost	9.9%	10.2%	10.5%

The operating costs for FBC 370 are expected to be higher on a cost per heat unit basis than FBC 530 units, however on a basis of percentage of capital costs, the operating costs are expected to be lower than for FBC 530. With a capital cost of $33.1 million/unit and estimated annual operating costs for a single unit of $3.0 million, the annual operating charge is 9% of the capital costs.

Sulphur removal costs are variable depending upon the sulphur content of the fuel source. Based upon a ratio of 3 Ca/S for removal of the required excess SO_2 production, the sulphur removal operating cost has been estimated using the following parameters:

- SO_2 removal required for all SO_2 in excess of 0.26 kg/GJ (the present environmental limits).
- 2.8 kg limestone required/kg SO_2 removed.
- limestone costs at $40/tonne delivered and stored.

Operating costs for SO_2 capture = excess tonnes SO_2/yr x 2.8 x $40/tonne.

These charges are added to operating costs in the **FUELOPTS** program.

Companies Producing FBC Equipment

There are a large number of FBC boiler manufacturers worldwide, however the North American market is more limited in scope. Appendix VI-1 lists both the Atmospheric Bubble Bed manufacturers and the Circulating Fluid Bed manufacturers. The industry leaders for design of FBC units readily adaptable to steam raising in the heavy oilfields are CE Natco, Struthers TIW Ltd., and Pyro Power Corporation.

To date the largest units produced for oilfield applications have been FBC 50 units. All presently available FBC units require field assembly therefore scale up costs will be lower than the cost of duplicating smaller units, and the use of larger units is anticipated. Appendix VI provides two very good recent references on FBC technology and indicates how numerous these units are in Europe and China.

Advantages

- Can safely burn high sulphur, low volatile coke.
- Use of limestone produces very low SO_2 and NO_x emissions.
- Can burn a wide range of solid fuels and can be adapted to liquid or gaseous burning.
- Uses fuels that cost a fraction of the natural gas fuel costs.
- Technology is becoming well enough developed for oilfield applications.

Disadvantages

- High initial capital cost.
- Equipment is complex to operate.
- Requires solid fuel handling and storage.
- Requires gas, oil or diesel fuel for start-up.
- Is not portable.
- Ash handling and disposal are necessary.
- Technology still "new" in oilfield application.
- Operating costs are higher than gas fired generators.

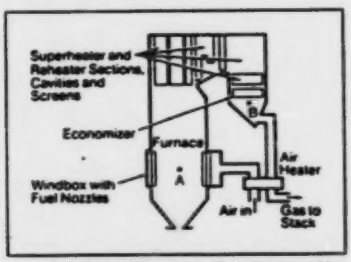
5.4.4 Pulverized Coal Fired Boilers (PCF)

Pulverized coal fired boilers have been in service since about 1925 when they began to encroach on stoker technology. Today, Pulverized Coal Fired (PCF) boilers are extensively in use for utility and industrial steam-raising applications in great numbers. There are however no PCF boilers in service for steam raising in oilfield applications. The major reason is that the basic recirculating water design of most boilers does not suit the once-through oilfield application.

The typical PCF recirculating boilers require inlet water of extremely pure quality with only a few parts per billion TDS. The unit is designed to burn specific coals and, due to burner and ash handling facilities design, must remain within the design fuel specifications to avoid fouling and slagging in the furnace. Generally boiler designs contain either a dry bottom ash removal system or a slag tap system. The dry bottom furnace keeps the burning temperature below the ash fusion temperature whereas the low ash fusion temperature coals in the slag tap furnaces burn at such high temperatures that the ash melts and is drained off in

liquid form. Accordingly the design of the ash removal system is determined by the available fuel types.

The elementary type of industrial boiler incorporates a boiler as heat sink and a heating system as a load to generate the thermal energy released by fuel fired to the boiler (see Fig. 5.9). The thermal transport medium is steam or hot water and in typical power plant applications it is returned to the boiler at a lower temperature level after dissipating heat in the turbine. In industrial applications steam may be supplied to process directly and not returned as condensed feedwater.



Total heat absorption by the primary working fluids in a steam generator—the water and steam—takes place between points A and B.

Figure 5.9
Typical PCF Furnace and Heat Exchange Design

In oilfield steam-raising applications the PCF boiler must operate on a once-through concept which requires great quantities of fresh water. Water purification of produced water is so expensive as to be impractical for PCF boiler technology, therefore the assumed technology requires about 55% fresh water super-heated by about 165°C in the steam boiler. After leaving the steam boiler the super heated steam enters a de-superheater where it is mixed with 45% de-oiled, zero-hardness produced water to produce 80% steam/20% water at desired pressures and temperatures. This technology is similar to that considered by Esso for Cold Lake in the late 1970's.

PCF Boiler Capital Costs

Cost estimates were requested for a 370 GJ/hr and a 530 GJ/hr unit. The estimates, provided by Babcock-Wilcox, are included in

Appendix V. The nominal cost difference of the two boilers is:

PCF 530	- $20,250.00
PCF 370	- 17,250.00
Difference	$ 3,000.00

Based upon the 45% greater steam generating capability in the PCF 530, and the 17% cost difference, this study only continued cost analysis for the PCF 530 (see Table 5.5).

Using a scale down factor of 0.67, a single unit will cost $\$67,210,000\ (1/2)^{0.67} = \$42,200,000$.

Table 5.5

2 Unit PCF 530 Boiler Capital Cost

Item	Cost $ x 1000
Boilers with Mountings	30,700
Feedwater Pump and Blowdown Tanks	740
Air Compressors	740
Steam Piping	6,000
Electrical and Instruments	6,000
Building, Paint, Insulation & Landscaping	7,960
Precipitator	5,000
Fuel Handling and Storage	8,400
De-superheater	2,270
Saline Heater	1,000
Ash Disposal Equipment	1,300
Water Purification Credit*	(4,400)
	$67,210

* Clean up of water is less costly than the required cleanup of water for the once through boiler as estimated by CH_2M Hill.

PCF Operating Cost

The operating costs, exclusive of delivered fuel charges, of the PCF Boilers are marginally lower than for FBC equipment for several reasons:

- Lower electric requirements by 36%.
- Lower maintenance costs by 13%.

Table 5.6

PCF 530 Operating Costs

Item	Number of Units (Cost in $ x 1000) 1	2	4
Electricity, @ $0.04/Kwh	862	1,501	2,613
Labour @ $25/Man hr.	705	1,202	2,050
Maintenance	1,160	1,759	2,666
Fuel Handling	300	455	689
Ash Handling	50	76	115
Water Purchase and Produced Water Removal	250	379	574
Total:	3,327	5,372	8,707
Operating cost as % of Capital Cost	7.9%	8.0%	8.1%

These figures indicate annual operating charges for a 4 x 530 system to be about 8.0% of the capital costs.

Rationale for Design

The use of PCF boilers using fresh water was the original operating concept utilized by Esso in their economic studies during the original Esso Cold Lake Board hearings. Esso completed their economics and pushed for use of gas instead of coal prior to testing the de-superheater concept even though they purchased some of the equipment for testing the technology.

The feedwater credit provides a substantial bonus to the capital costs and, though not considered in operating costs, should provide a modest increase in operating cost. This credit represents the difference between using PCF 530 with purified fresh feedwater (55%) mixed with near zero-hardness produced water (45%) ex-generator versus other steam raising technologies utilizing partially cleaned fresh water (35%) and partially cleaned produced water (65%) as steam generator feed water. This credit is very substantial, and by removing the necessity of full clean-up of produced water, simplifies the produced water handling operation considerably.

PCF Advantages

1. Only fresh water required to meet boiler cleanliness.
2. Produced water only needs oil removal and softening.
3. Can use low cost coal fuel.
4. Ash is non-toxic.
5. Boiler technology is well established.
6. Thermal efficiency is +85%, reliability +90%.
7. Available in a wide range of sizes.

PCF Disadvantages

1. High initial capital and operating cost.
2. Lengthy field erection required.
3. System is not portable.
4. Can only use 45% produced water.
5. Design of de-superheater required to avoid scaling.

5.4.5 PCF Once-Through Steam Generator

The concept of using pulverized coal firing for a 190 GJ/hr size steam generator was reviewed. Based upon the concept of 3 to 6 steam generators on each production pad, the steam generators would require a maximum of two pulverizers and an integrated fuel feed system. Industry sources did not think the concept impractical and the response was generally favorable among the boiler manufactures.

Conceptually, a separate pulverized coal fired "Dutch Oven" type furnace could be attached to a remote heat exchange steam generator. Several aspects of coal burning would, of necessity, be included. For example, the ash must be collected from the flame prior to the hot gases entering the radiant section to control fouling. In all probability the water pipe spacing would need to be widened and either less piping used or else the radiant section would require expanding. Integration of fuel and ash handling systems conceivably provide real economies of scale with expanded sizes of operations.

Cost data provided by TAU indicate that the cost of these units would not be unlike the capital cost of PCF boiler equipment or FBC equipment if numerous units were installed. Accordingly, specific economics were not completed on these units (in this study) and it is assumed that cost levels would be similar to the other coal fired technologies.

5.4.6 Other Coal Burning Technologies

Coal-Water Mixtures (CWM)

There are several very promising coal-water technologies developing at present, however limited commercial development has commenced. In Sweden, Fluid Carbon and Carbogel, both coal-water mixtures at about 75% coal, 24% water and 1% additive are being researched as substitutes for Coal-Oil and Coal-Oil-Water mixtures. The initial plant capacity at Mulmae, Sweden uses 250 kilotonnes of coal annually (equivalent to 125 kilotonnes heavy fuel oil).

These coal-water mixtures appear to have a promising future. A particular exciting application in the heavy oil fields would be a combination of coal slurry transport to the demand centre and then combustion using Carbogel or FluidCarbon technology.

Coal-Oil Mixtures (COM)

COMs are the most accepted of the coal-liquid suspensions in terms of level of production and history of use. Normally, 30% to 50% by weight of pulverized coal in fuel oil is used (with or without additives) to produce the suspended coal-oil mixture. This technology is very sensitive to two major factors:

i) the price of the fuels, and
ii) the capital cost of ash collection and handling facilities.

Plant scale tests to date have not been encouraging because the marginal benefits do not seem to outweigh the higher capital costs.

6.0 REGULATORY AND ENVIRONMENTAL ISSUES

6.1 Coal

6.1.1 Mining

The estimated price of coal loaded into trains or trucks includes all costs required to comply with regulatory requirements. While these costs vary from mine to mine, they are reflected in the estimated "unit-train-loaded" costs per tonne of coal. No other "regulatory" costs are material to the cost of coal.

6.1.2 Transportation

The principal environmental concern relative to coal transportation by rail is the wind loss of fine coal from open hopper cars. The currently accepted control method is the spraying of the loaded cars with a latex solution.

Coal and coke haulage by truck involves more labour and creates greater socio-economic problems than train haulage. The major social problem is heavy coal hauling truck traffic on the public roads. There is no doubt that public concern over 24 hour haulage will rise if a great quantity of trucks are used. The road damage caused by the maximum weight coal trucks could result in higher licencing costs (however, this is not expected to be a major factor). A cost allowance of 10% on truck tariff base rates was incorporated to compensate for these social costs.

Road bans during spring thaw will, if imposed, significantly increase coal transportation costs either by forcing an idle period or restricting load size. A similar allownace of 10% on base truck rates to compensate for this anticipated cost increase has been included in the estimates.

The major environmental impact of slurry pipeline transport will be providing fresh water supply and obtaining right of way access. We believe water supply is a credit to the system because off site water must be pumped on-site to provide the 35% make-up water balance. We did not, however, define and apply such a credit to the system. The cost of pipeline right of way has been included as a small component of the pipeline capital costs and, ultimately, the pipeline tariff. Rights of way are not considered a major environmental issue because pipelines are very common in Alberta and are readily accepted by landowners.

6.1.3 Coal Unloading and Storage

It is probable that approval, under the Alberta Clean Air Act, for a project based on coal fuel supply may stipulate dust control measures for both the unloading facilities and open stock piles. For open air stock piles, a water or latex solution spray system, activated when ambient wind velocities attain about 15 km/hour, is easily implemented. Allowances for dust control are included in unloading capital and operating costs.

During the winter season railcars are exposed to freezing temperatures. Spraying the rail car's interior surfaces prior to loading eliminates unloading delays due to the freezing of coal to the hopper cars. An annual allowance of $0.05 per tonne of delivered coal is included for this preventive measure. Rail rates include this cost.

6.1.4 SO_2 Emissions

The Alberta Department of the Environment has evolved emission guidelines for new fossil-fuel fired power generating plants and has advised that these new guidelines are now adopted. For sulphur dioxide the maximum permissible SO_2 quantity in the flue gas is 0.60 lbs of SO_2 per 10^6 BTU (0.258 kg/GJ). Most coals meet or are near to meeting this restriction.

Steam raising plants must meet ambient air quality standards for pollutants other than sulphur dioxide, but the principal concern is sulphur dioxide. Currently, the guidelines require that ground level concentrations of SO_2 attributable to an identifiable source shall not exceed:

- an average of 450 microgram/m^3 during any 1 hr period
- an average of 150 microgram/m^3 during any 24 hr period
- an average of 30 microgram/m^3 during any 1 month period

Empirical relations between ambient ground level concentration of SO_2 attributable to tar sands upgrading plant stack emissions and stack height, stack diameter, flue gas temperature, flue gas volume and flue gas SO_2 concentrations have been established for the Fort McMurray area. Definitive site assessment requires stack and meteorological parameters specific to the plant site.

Where necessary, an increase in capital cost up to 20% of original capital cost is included to provide SO_2 removal equipment in the furnace technology for PCF equipment. With FBC equipment there is no capital cost surcharge, however there will be an operating cost addition to purchase and deliver sufficient limestone to absorb the required levels of SO_2. With the high SO_2 content of coke, this charge can substantially add to operating costs.

6.1.5 NO_x Emissions

NO_x emissions are increasingly recognized as significant pollutants of the environment, and accordingly the recently enacted guidelines in the Clean Air Act are set at 0.5 lb/10^6 BTU (0.215 kg/GJ) for solid fuels. As for SO_2 emissions, compliance is measured on a 72 hour rolling averaging period. The current state of the art of PCF and FBC furnace design and operation has advanced to the point that this guideline can be attained without special technological provisions.

6.1.6 Particulates

The present Alberta guideline relative to particulate emissions sets a maximum permissible concentration of 0.03kg/GJ of heat input. For the coal sources examined in this report, both guideline objectives (which are comparable in effect), require a 99.5% removal of ash prior to venting exhaust of flue gas to the atmosphere. Current state of the art systems of bottom ash and fly ash removal (including electrostatic precipitators) make a 99% removal attainable. In view of the marginal short-fall of only 0.5%, no allowance was made for capital costs for improvements on the ash removal system, particularly as regards fly ash removal, beyond the normal levels.

6.1.7 Ash Disposal

It is assumed that ash removal to, and disposal in, an ash pond is technically feasible and environmentally acceptable. A conservative allowance of $1.50 per tonne of removed ash is included in the annual operating costs.

6.1.8 Labour Force Effects

The increase in the labour force that will be required when steam is generated using coal rather than natural gas as fuel is estimated at 40 to 50 persons/year. This increase is small compared to the total labour force on site and no special capital or operating cost allowance is required to accommodate socio-economic consequences.

6.1.9 E.R.C.B. Views on Coal Usage for Steam Generation

In the recent past, the Energy Resources Conservation Board examined the question of the use of coal versus natural gas for steam generation several times when dealing with applications by Esso Resources Canada Limited relative to the Cold Lake Steam Injection project. During October, 1979, when Esso's estimated coal requirement was for 1.2 megatonnes/year and the applicant preferred the use of natural gas on economic and environmental grounds, the ERCB nevertheless rejected the natural gas option, and criticized the applicants economic and environmental data. The Board, while stating that it viewed the fuel alternatives (coal and natural gas) as having equal merits in many respects, considered the natural gas alternative to be an inappropriate use (for steam generation) of a high value energy resource, and decided that, from a provincial overall benefit perspective, a marginally greater benefit was associated with the use of coal.

During February, 1981, the ERCB re-examined the fuel option question when dealing with a further application by Esso, in which the applicant requested permission to use natural gas on the grounds that the reduced make-up fuel requirements (0.4 megatonnes/year) resulted in increased disadvantages of coal relative to use of natural gas. In deciding the application, the Board approved natural gas as the make-up fuel, "as long as actual use does not significantly exceed the requirements anticipated in the application". Should a significant increase over approved quantities used occur, the applicant would be required to file a review with the Board and conversion to coal or other make-up fuel was not excluded as a possible outcome of such a review. Since Esso has not constructed an upgrader on-site, the off-site fuel requirements are now greater than their original 1979 projections. Nevertheless, natural gas is still the fuel in use.

6.2 Petroleum Coke and By-Products

The major potential environmental problems associated with burning coke are the result of the high SO_2 content and the heavy metals contained in the fly ash (Va, Ni, Ti). Coke can be burned in FBC units where the sulphur can be scavenged by limestone and the resultant $CaSO_4$ mixed with the fly ash for disposal. These waste products may require special disposal techniques however the quantities are not large. Other by-product combustion present similar concerns and require similar treatment.

6.3 Summary of Environmental Considerations

In an environmental evaluation of gas, coal, coke and residual oil, where the issues are delivery, storage and the combustion products, the fuels can be ranked in increasing environmental impact as follows:

- **NATURAL GAS**
- **RESIDUAL OIL**
- **COKE**
- **COAL**

7.0 TECHNICAL AND ECONOMIC PARAMETERS

There are a large number of assumptions that must necessarily be made prior to carrying out an economic evaluation. The tables and graphs following summarize the assumptions, both technical and economic, that are implicit in the economics presented in Section 8.0. They are also the primary data entered into the economic program. Changes in these tables will alter the economic results very directly.

7.1 Steam/Oil Ratios

The major purpose of selecting a steam/oil ratio is to establish the fuel demand for each region. Steam/oil ratios provided by different operators in the various producing regions vary widely both within a given region and over time. Steam injection cycles vary widely in "shape", amplitude and duration. Nevertheless, single "representative" ratios have been selected for each region that:

i) are within the ranges provided by the operators,
ii) are "self-consistent" with respect to oil gravity, and
iii) reflect a "steady-state" production value past the project "break-in" phase.

TABLE 7.1

STEAM PARAMETERS

STEAM/OIL RATIOS:		
Location	**m3/m3**	
Lindbergh	3.70	
Cold Lake	3.00	
Peace River	4.00	
C.Athabasca	5.00	
N.Athabasca	5.00	
GENERATION PARAMETERS:		
Energy Efficiency	85%	
Generator Load	100%	
Operating Days	365	
Heat Content(GJ/m3)	2.155	
UNIT CAPACITY:		
	Fuel (GJ/Hour)	**Avail.**
gas190	190	90%
pcf330	330	85%
fbc370	370	85%
fbc530	530	85%
NAT. GAS PARAMETERS		
Price ($/K m3)	93.545	
HeatContent(GJ/K m3)	37.228	
DE-SULPHURIZATION:		
SO2 Limit(Kg/GJ)	0.258	
pcf:Capital Fraction	20.00%	
fbc:$/Kg SO2(opertg)	0.112	

7.2 Combustion and Generation Parameters

The largest practical gas fired, pulverized coal fired and fluidized bed combustion units were selected as representative of the current "state-of-the-art". Combustion facility requirements were assumed to be met by multiples of the units shown in Table 7.2.

Table 7.2
Fuel Burning Units

Unit Capacity:	Fuel (GJ/Hour)	Availability
gas190	190	90%
pcf530	530	85%
fbc370	370	85%

Where fractions of a unit are indicated, it is assumed that the production volume would be adjusted upwards or downwards to correspond with an "exact" integer number of units. Alternatively, it could be assumed that some sizing adjustments of the combustion units would remove the need for "fractional units". Whether production volumes or unit capacities are assumed to be the adjusting variable, carrying fractional units through the economic analyses improves the "fairness" of comparisons between the alternatives. Some measure of the effects of unit sizing change is provided by the inclusion of the analyses of the fbc370 unit, which does not have the economies of scale of the fbc530 unit, but does offer a lower capital and operating cost.

7.3 Fuel Costs

7.3.1 General

The costs, apart from combustion and steam generation, associated with each fuel alternative are:

i) price at the point of supply,
ii) transportation to production site,
iii) on-site handling and storage,
iv) ash disposal, and
v) de-sulphurization.

7.3.2 Natural Gas

Natural gas of pipeline quality is assumed to be available to each producing region at a flat rate of $2.51/GJ ($93.54/K m^3 or $2.65/Mcf). This price reflects the opportunity cost/value of natural gas which could be committed to other domestic or export markets. It also assumes an "arms-length" purchase from outside the producer organization such that all royalties are included. The flat price also reflects the competition within Alberta which determines price at the delivery point rather than the wellhead.

Table 7.3
Natural Gas Parameters

Price ($/K m^3) - $93.545
Heat Content - 37.223 GJ/K m^3

7.3.3 Lease Crude

Due to the high opportunity value of lease crude, it is not examined in detail in the analysis.

7.3.4 Coke

The high sulphur content of coke requires combustion in a fluidized bed environment and requires limestone to react with the SO_2 to produce $CaSO_4$. Coke transport is also more restricted; only truck and rail transport need be considered. The price of coke is assumed to be $17.25/tonne F.O.B. Tar Island or Mildred Lake, and $20.00/tonne F.O.B. Lloydminster, and applicable transport modes are used to deliver the fuel. During combustion an estimated 2.8 tonnes of limestone per tonne of excess SO_2 are brought on site (C$40/tonne)

and consumed. In other words, sulphur capture is considered to be an operating cost rather than a capital cost. The cost is assumed to be $0.112/kg SO_2 and includes the cost of delivering the limestone to the site and dispositing of the resultant gypsum.

TABLE 7.4

COKE DATA

Source	Heat Content (GJ/Kg)	Sulphur Content	F.O.B. Price ($/T)	($/GJ)	SO2 Emission (Kg/GJ)
Tar Isl.	33.50	5.9%	17.25	0.51	1.76
MildredL	29.50	6.8%	17.25	0.58	2.31
Lloydmin	29.86	3.0%	20.00	0.67	1.00

7.3.5 Coal

The factors contributing to the cost/unit of generated steam with coal as fuel are:

i) Coal price - set at $12.35/tonne at 7 bcm/trc scaled at 0.6 (see Fig. 7.1 for price variation at differing strip ratios),

ii) Transportation - can be by truck, rail (2 modes) or pipeline. The transport cost is minimized by least cost analysis using volume, distance and mode of transport,

iii) Burn Technology - can use either pulverized coal fired or fluidized bed technology; costs must include ash disposal and SO_2 capture,

iv) SO_2 content - FBC units must include limestone in operating costs. PCF units are subjected to increased capital costs to capture sulphur using Flue Gas De-sulphurization if SO_2 capture is necessary. The PCF capital factor is:

$$\frac{1.2(S-L)}{L} \quad \text{if } S>L, \text{ where } S = \text{kg } (SO_2)/\text{GJ burned}, \; L = SO_2 \text{ emission limit}$$

or 1.0, if S<L

The basic data relevant to the coal deposits considered is included on Table 7.5.

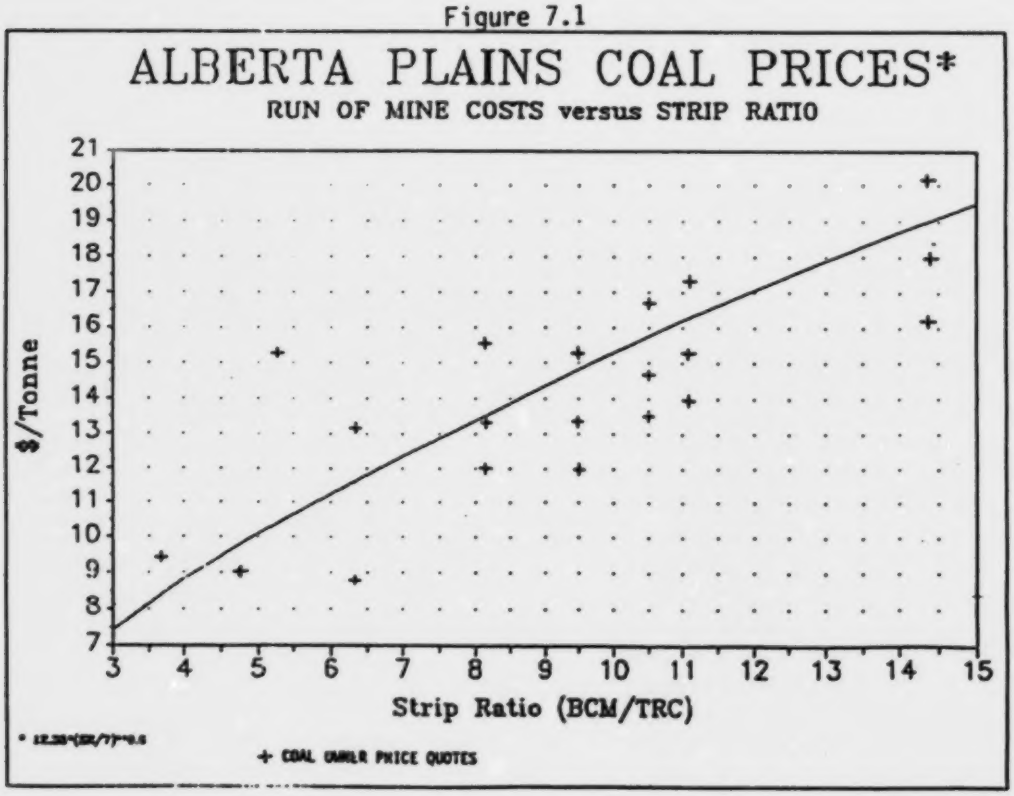
TABLE 7.5

COAL DATA

Source	Strip Ratio (BCM/T)	Heat Content (GJ/T)	Sulphur Content	Mine Gate F.O.B. Price ($/T)	($/GJ)	SO2 Emission (Kg/GJ)
Morinvll	6.4	18.6	0.32%	11.70	0.63	0.17
Barrhead	11.0	18.2	0.50%	16.20	0.89	0.27
Camrose	5.9	18.3	0.46%	11.15	0.61	0.25
Genesee	5.9	20.2	0.22%	11.15	0.55	0.11
Isle Lk.	5.0	19.0	0.23%	10.09	0.53	0.12
Thorhild	8.2	17.0	0.30%	13.58	0.80	0.18
Heatburg	4.5	18.0	0.30%	9.47	0.53	0.17
Fox Crk.	5.3	16.1	0.30%	10.45	0.65	0.19
ClearHls	10.0	16.0	0.35%	15.30	0.96	0.22
Halkirk	9.5	18.1	0.50%	14.83	0.82	0.28
L.Slave L.	12.0	15.9	0.14%	17.07	1.07	0.09

NOTE: Price($/T) = 12.35*(SR/7.0)**0.6

Figure 7.1



7.4 Fuel Transport Costs

The fuel transport assumptions are listed in Table 7.6 to 7.11 and Figure 7.2.

TABLE 7.6

CONNECTING DISTANCES - OLD ROAD
(Km)

	Lindbergh	Cold Lake	Peace River	C.Athabasca	N.Athabasca
Morinville	230.0	280.0	475.0	325.0	445.0
Barrhead	300.0		395.0	300.0	
Camrose	200.0	350.0		512.5	625.0
Genesee	330.0				
Isle Lake	315.0	350.0	425.0	450.0	562.5
Thorhild	215.0	225.0		280.0	392.0
Heatburg	350.0				
Fox Creek			237.5		
Clear Hills			134.4		
Halkirk	250.0				
L.Slave Lake					
Tar Island			720.0	90.0	80.0
Mildred Lake				100.0	70.0
Lloydminster	100.0	225.0			

TABLE 7.7

CONNECTING DISTANCES - NEW ROAD
(Km)

	Lindbergh	Cold Lake	Peace River	C.Athabasca	N.Athabasca
Morinville	4.8	4.8	4.8	4.8	4.8
Barrhead	0.0		0.0	0.0	
Camrose	6.5	6.5		6.5	6.5
Genesee	0.0				
Isle Lake	8.1	8.1	8.1	8.1	8.1
Thorhild	0.0	0.0		0.0	0.0
Heatburg	0.0				
Fox Creek			19.0		
Clear Hills			68.8		
Halkirk	0.0				
L.Slave Lake					
Tar Island			0.0	0.0	0.0
Mildred Lake				0.0	0.0
Lloydminster	0.0	0.0			

TABLE 7.8

CONNECTING DISTANCES - OLD RAIL
(Km)

	Lindbergh	Cold Lake	Peace River	C.Athabasca	N.Athabasca
Morinville	211.2	-255.0	402.2	-397.4	-460.0
Barrhead	244.4		452.4	-432.8	
Camrose	240.6	-340.0		-487.5	-537.5
Genesee	264.3				
Isle Lake	272.6	-350.0	570.4	-487.5	-537.5
Thorhild	189.2	-210.0		-314.8	-364.8
Heatburg	375.0				
Fox Creek			120.0		
Clear Hills			0.0		
Halkirk	475.0				
L.Slave Lake					
Tar Island			-900.0	50.0	0.0
Mildred Lake				50.0	0.0
Lloydminster	85.6	-200.0			

NOTE: Negative entries indicate upgrading required.

TABLE 7.9

CONNECTING DISTANCES - NEW RAIL
(Km)

	Lindbergh	Cold Lake	Peace River	C.Athabasca	N.Athabasca
Morinville	28.8	25.0	52.8	57.6	60.0
Barrhead	38.4		57.6	67.2	
Camrose	24.4	25.0		50.0	62.5
Genesee	38.4				
Isle Lake	30.4	41.0	49.6	56.3	72.0
Thorhild	14.8	25.0		53.2	62.5
Heatburg	22.4				
Fox Creek			132.0		
Clear Hills			125.0		
Halkirk	22.4				
L.Slave Lake					
Tar Island			0.0	82.0	65.0
Mildred Lake				88.0	65.0
Lloydminster	22.4	50.0			

TABLE 7.10

CONNECTING DISTANCES - PIPELINE
(Km)

	Lindbergh	Cold Lake	Peace River	C.Athabasca	N.Athabasca
Morinville	195.0	225.0	345.0	290.0	395.0
Barrhead	240.0		310.0	290.0	
Camrose	130.0	210.0		350.0	455.0
Genesee	240.0				
Isle Lake	265.0	300.0	365.0	355.0	460.0
Thorhild	150.0	175.0		245.0	350.0
Heatburg	225.0				
Fox Creek			200.0		
Clear Hills			125.0		
Halkirk	190.0				
L.Slave Lake					
Tar Island				50.0	37.5
Mildred Lake				50.0	37.5
Lloydminster	75.0	150.0			

TABLE 7.11

TRANSPORTATION RATE PARAMETERS
($/T-Km)

	A	B	C	D
Truck	-3.3700E-03	-5.4380	0.0590	0.0000
Car-Lot	-4.8870E-03	-3.2450	0.0368	0.0050
Unitrain	-2.3650E-03	-3.4432	0.0212	0.0050
Pipeline	-2.8000E-03	-1.3281	0.0400	0.0000

Rate = exp(A*KT+B) + C, where KT = K Tonnes.
If upgrading required,
Rate = Rate + D

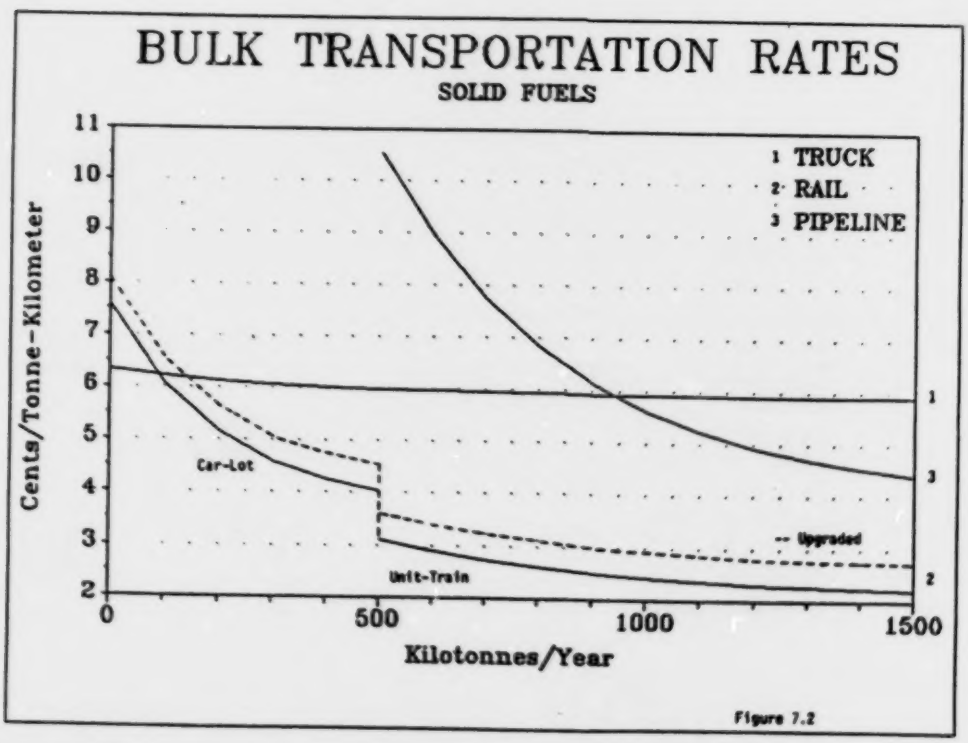


Figure 7.2

7.5 Capital Costs

All inclusive capital cost estimates were obtained for single and multiple orders of the steam generator units through discussions with suppliers, operators and combustion engineers. Price/volume breaks were assumed to follow the exponential rule:

$$\text{Total Order Cost}(n) = \text{"One-of" Cost} \times n^{s},$$

where n is the order quantity, s is a scale index >1, and the "One-of" Cost is the supplier quote for a single copy of each combustion unit. Under this assumption, the cost of an order less than one would be "scaled up" by the s-exponent of n, in this case 0.86 for gas fired and 0.67 for all types of solid fuel fired equipment. The scale indices serve the duel role of accounting for price/quantity breaks as well as cost reductions resulting from shared or common facilities. This relationship, while not exact, is but one of the simplifying assumptions made for this study. It is estimated that distortions introduced by this assumption are within the uncertainties associated with the unit costs. Refer to Fig. 7.3 and Table 7.12.

The combustion unit capital costs do not include de-sulphurization equipment or other fuel-dependent components. Only after the SO_2 content of the available fuel exceeds regulated levels are the "add-on" de-sulphurization expenditures for coke and coal included in capital/operating costs.

Tie-in and on-site distribution system costs for natural gas and/or crude burned as fuel are highly dependent upon the "pad" size, distribution, nearness to supply points (pipelines, producing wells, etc.) and other non-standardizable variables. These costs are indicated by several project operators to be quite nominal. Therefore, a flat rate rather than a distance related charge for natural

Figure 7.3

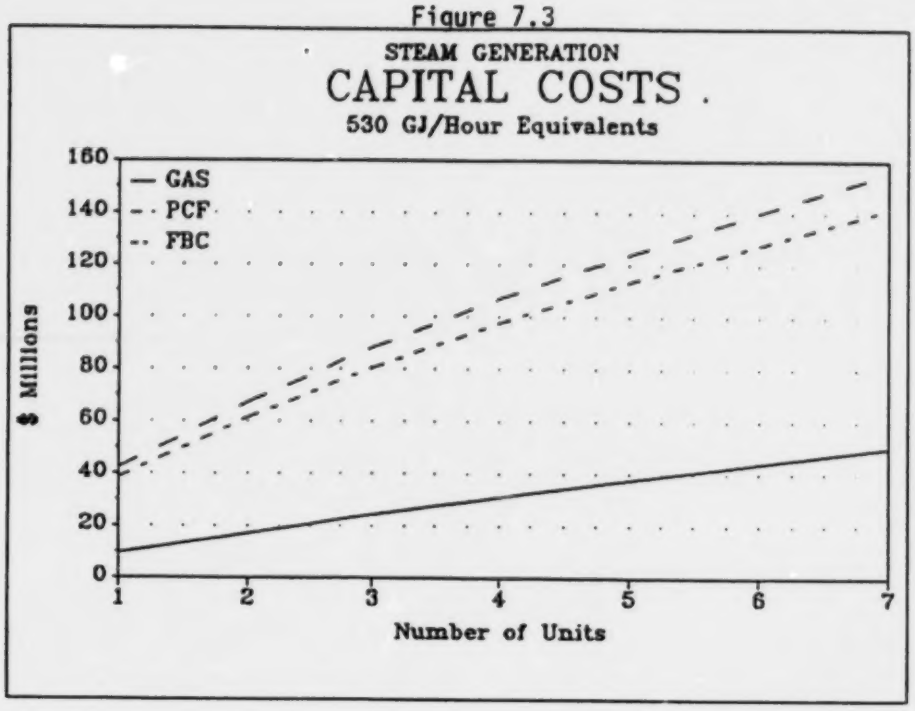
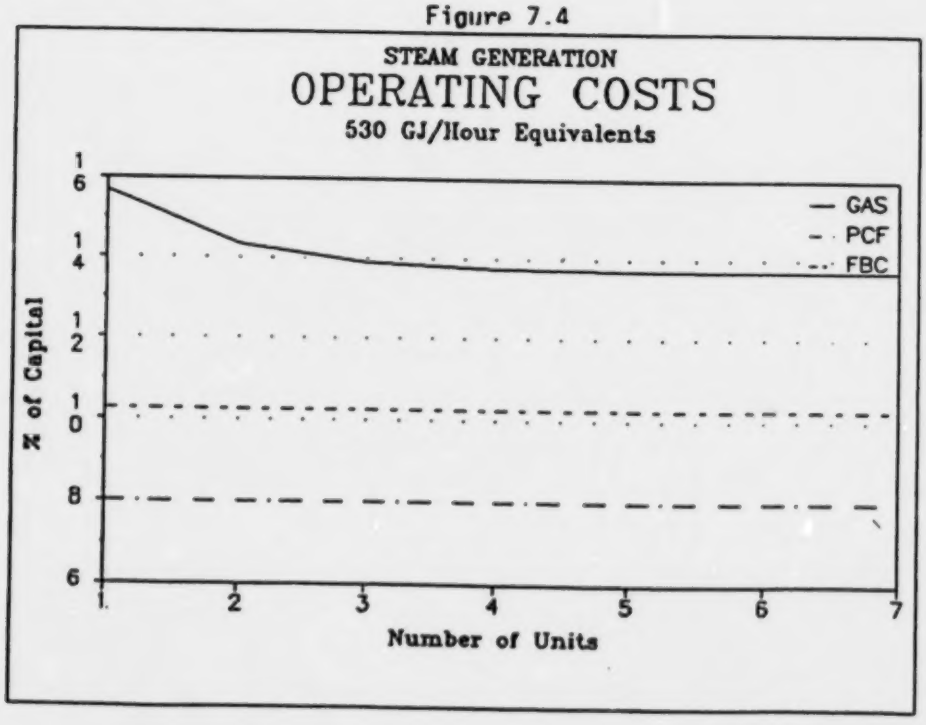


Figure 7.4



gas was assumed at $5,000/K m^3. This assumption introduces a tie-in/distribution capital cost of less than 10% of the steam-generation facilities for the entire capital cost associated with gas delivery. Equipment capital costs are shown on Table 7.12.

7.6 Operating Costs

Annual operating costs for steam generation are estimated by each mode of combustion and at several levels of production. These costs include labour, electrical power, and other consumable materials and supplies but exclude the cost of steam generator fuel. Because of large fixed labour costs associated with PCF and FBC units, operating costs fall toward a limiting fraction of capital expenditure as shown in Table 7.12 and Fig. 7.4. In order to simplify the analyses within a "relevant range" of units, annual operating costs are assumed to be a fixed fraction of capital close to the limiting values. Distortions to the comparative economics introduced by this simplifying assumption are, again, well within the uncertainties associated with capital costs.

TABLE 7.12

UNIT CAPITAL & OPERATING COSTS

Unit	Capital Cost ($ 000)	Scale Index	Annual Charge Capital	Operating C	B	A
gas190	3,900	0.86	21.0%	13.70%	-2.7728	-0.4125
pcf530	42,200	0.67	21.0%	8.00%	-10.0000	0.0000
fbc370	33,000	0.67	21.0%	10.25%	-10.0000	0.0000
fbc530	38,500	0.67	21.0%	10.25%	-10.0000	0.0000
road($/K)	300	0.00	21.0%	1.00%		
rail($/K)	400	0.00	21.0%	1.00%		
gas($/Mm)	5	0.00	21.0%	0.50%		

NOTE: road($/K) is the road construction capital cost per kilometer.
rail($/K) is the rail construction capital cost per kilometer.
gas($/Mm) is the gas distribution capital cost per million m3 of natural gas.

Op.Cost = (EXP(A*n + B) + C/100)*Capital Cost,

where "n" is number of units.

Desulphurization:

SO_2	Limit (Kg/GJ)	0.258
pcf:	Capital Fraction	20.00%
fbc:	S/Kg SO_2 (operts)	0.112

Similarly, operating and maintenance costs for dedicated new road, new rail, and new gas distribution lines are estimated as fractions of capital expenditure.

7.7 Oil Production Levels

In order to study the economics of the project sites at various production levels, the program is designed for analysis at various production levels. The oil production levels used in this study are as follows:

800 m^3/day	(5,000 BOPD)
1,600 m^3/day	(10,000 BOPD)
2,400 m^3/day	(15,000 BOPD)
3,200 m^3/day	(20,000 BOPD)
4,800 m^3/day	(30,000 BOPD)
6,400 m^3/day	(40,000 BOPD)

7.8 Financial and Fiscal Assumptions

The financial assumptions used in the economic analysis are:

i) Debt-Equity Ratio = 75%-25% with debt at 11% annual interest rate, equity at 15% rate of return after tax,
ii) A 10% capital allowance for funds used during construction,
iii) Municipal and property taxes are estimated to be 2.6% of total plant, property and equipment investment,
iv) Straight line depreciation is used for book purposes over the economic life of the respective capital assets (for FBC and PCF, 20 years; for gas 190 units, 10 years), and
v) An average current income tax allocation (allowance) is included.

The consequence of these assumptions are:

Capital cost	= 100%
Rate Base (incl. AFUDC)	= 110%

Capital Service Factor:

Depreciation (5% of 110%)	= 5.5%
Return Ratio Base	12%
(75% @ 11% = 25% @ 15%)	= 12.9%
Property Taxes & Insurance	= 2.6%
Total	21.0%

All fuel prices and costs are assumed to include royalties (Crown or freehold). Although most natural gas is owned and produced by oil companies, in only some circumstances is the gas wholly owned by the heavy oil field operator thus permitting avoidance of Crown royalty payments. Accordingly, this study assumes market purchases from within Alberta and assumes normal royalty payments to government and private fuel owners. The sale prices of coal and coke are also assumed to include Crown and freehold royalties.

7.9 Economic Assumptions and Terminology

Currency - All dollar amounts are expressed in constant 1985 Canadian dollars. All hydrocarbon prices are expressed as the 1985 equivalent of expected 1990 values, and reflect the anticipated relationships at that future point in time.

Startup - A common project startup at January 1, 1990 is assumed for coal mines, other production facilities, and transportation facilities. This assumption is a matter of convenience only.

Economic Life - A common economic life of 20 years is assumed for all crude oil producing properties and all related production facilities, including transportation and combustion facilities. For rate-making and coal supply-pricing purposes, coal mines and slurry pipelines are assumed to operate for 25 years. The economic life assumption is important for the estimate of annual capital service charges for new capital facilities (see Financial Assumptions).

Unit Costs - The unit costing approach used assumes utility rate-making methodology which, in turn, depends upon the financial results of operations as recorded in the financial statements. These "book" results may provide different economic cross-over points than discounted cash flow (DCF) methods. This is to be expected due to the different time frames viewed by each method. Nevertheless, both the unit-cost and cash flow methods provide useful economic comparisons between alternate fuels.

Differential Economics - Natural gas is the reference fuel for steam raising to which all other fuels are compared. Because very different capital and operating costs are incurred using different fuels, a direct dollar comparison is not readily understood. Differences stand out much more clearly. Therefore the economics of these differences, that is the "differential economics", represents the benefits (or costs) over and above those of natural gas. These differences also form annual cash flow differences upon which conventional payback and DCF analyses may be applied.

Internal Rate of Return (IRR) - The IRR is the DCF answer to the question, "How much interest can the project afford to pay for the increased capital associated with the alternate fuel and still break-even relative to natural gas?" Because the cash flows are in constant 1985 dollars, the IRR results obtained should be increased by the rate of inflation before being compared with prevailing interest rates.

Net Present Value (NPV) - The NPV is the net present worth of using the alternate fuels instead of natural gas, assuming an inflation-free or "real" cost of capital as a discount rate. A positive NPV at any given discount rate implies economic benefits over natural gas.

Gas Equivalent Capital - The gas equivalent capital represents the capital cost for the alternate fuel that yields steam of equal cost to that raised by natural gas. Operating costs are adjusted in proportion with the capital costs. De-sulphurization is included in the cost of steam comparisons but the gas equivalent capital is presented on a "before de-sulphurization" basis.

8.0 Economic Evaluation

8.1 Introduction

The economic evaluation of the use of alternative fuels for enhanced hydrocarbon recovery requires evaluation of many aspects of the costs and benefits of the particular fuels. From a macroeconomic or governmental viewpoint, the optimum choice of fuels would maximize net benefits to the province and country with all socioeconomic and environmental issues considered. From the point of view of in situ steam project owners, the primary concern is to minimize the costs associated with steam generation consistent with efficient production of crude oil. If the natural gas burned (in Alberta) to generate oilfield steam could be sold into higher margin domestic and export markets and solid fuels (without such markets) burned instead, then provincial benefits from these resources could be maximized. The objective of this study is to show that project economics can benefit from the use of solid fuels just as the province could benefit from the joint development of under-utilized resources. The emphasis within this study is upon the microeconomics of steam-raising fuels in-situ steam enhanced oil recovery projects.

The intent of the economic evaluations carried out within this study is **not** to assess the economic viability of any single project but rather to assess the economic attractiveness of substituting solid fuels for natural gas in the generation of the steam. Acceptable overall project economics using natural gas are assumed. That is, natural gas provides the "zero" of reference for the economics of the alternative fuels.

These economics are developed before income taxes. This conservatively biases the results in favor of lower capital cost of natural gas for taxable project owners.

All dollar amounts are specified in 1985 constant dollar "real" terms. Therefore all results, including rates of return, are inflation free. Price and cost relationships are intended to

reflect 1990 market conditions discounted to 1985. Prevailing interest rates should be reduced by the current inflation rate before being used as a reference for project rates of return calculated on constant dollar cash flows.

The economics are developed by two methods:

a) a utility compensatory cost of generated steam approach,
b) a discounted cash flow (DCF) approach based on differential expenditures (alternative fuel less natural gas expenditures).

The utility cost-of-steam approach provides a conservative accounting or "book" measure of relative economic attractiveness. Although many compromises and conventions are involved in its estimate, utility cost of steam is a concept that project operators can relate to.

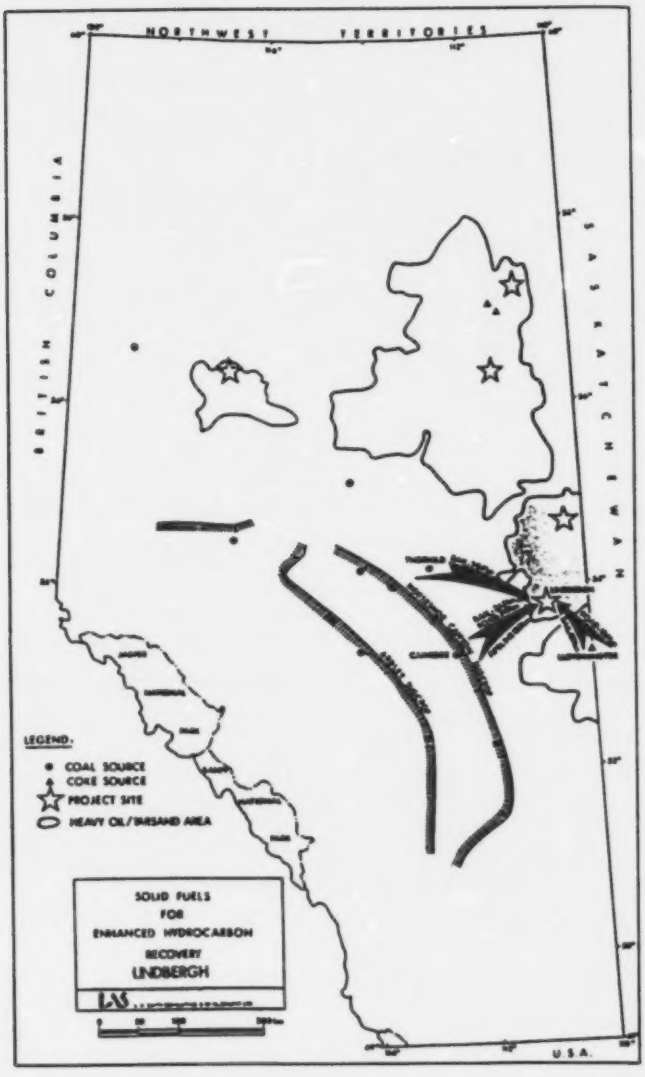
DCF economics on differences of cash flows is less readily understood than cost of steam. The internal rate of return (IRR) derived from the differences in cash flows between natural gas and alternative fuel steam generation is an answer to the question, "How much interest can the project afford to pay on the incremental capital investment (over natural gas) in alternative fuel-burning steam generation facilities?" This IRR can then be compared with prevailing interest rates or other measures of the cost of capital. If the project IRR exceeds the interest rate, then the project would make money on borrowed funds (all other risks ignored).

The economic objective is to find the scale of operation or level of crude production at which the alternative fuel can begin to provide steam at equal or lower cost than natural gas. The crude production level at which equivalence of steam cost occurs is herein called the "cross-over point". Below the cross-over point the economics are increasingly unfavorable. Above the cross-over point the economics are increasingly favorable. Thus the cross-over point is the economic "break-even" level of production.

8.2 Lindbergh

The location and logistics of the Lindbergh producing area and selected site are illustrated in Figure 8.1.

Figure 8.1
Lindbergh - Project Site



8.2.1 Site Facilities

The steam generator and steam generator fuel requirements at Lindbergh follow the assumptions listed in the economics assumptions section. Table 8.1 shows the steam generator capital and operating costs (ex fuel) by combustion mode. Costs for the solid fuel generators do not yet consider the fuel source and so do not include de-sulphurization components.

Table 8.1

STEAM CAPITAL & OPERATING COSTS

Lindbergh

STEAM GENERATION PARAMETERS						
Steam/Oil Ratio(m3/m3)		3.70				
Steam Heat Content(GJ/m3)		2.15				
PRODUCTION						
Oil(m3/day)	800	1,600	2,400	3,200	4,800	6,400
Steam(K m3/year)	1,080	2,161	3,241	4,322	6,482	8,643
FUEL CONSUMED(TJ/y)	2,739	5,478	8,217	10,957	16,435	21,913
STEAM GENERATORS:						
gas190 Units	1.83	3.66	5.49	7.31	10.97	14.63
Capital Cost($ K)	6,554	11,895	16,858	21,590	30,598	39,187
Annualized($ K):						
Capital	1,376	2,498	3,540	4,534	6,426	8,229
Operating	1,090	1,794	2,419	3,024	4,213	5,374
Total	2,467	4,292	5,959	7,558	10,638	13,604
pcf530 Units	0.69	1.39	2.08	2.78	4.16	5.55
Capital Cost($ K)	33,042	52,571	68,981	83,645	109,754	133,085
Annualized($ K):						
Capital	6,939	11,040	14,486	17,565	23,048	27,948
Operating	2,645	4,208	5,522	6,695	8,785	10,653
Total	9,584	15,248	20,008	24,261	31,834	38,601
fbc370 Units	0.99	1.99	2.98	3.98	5.97	7.95
Capital Cost($ K)	32,872	52,302	68,628	83,217	109,192	132,404
Annualized($ K):						
Capital	6,903	10,983	14,412	17,476	22,930	27,805
Operating	3,371	5,363	7,038	8,534	11,197	13,577
Total	10,274	16,347	21,449	26,009	34,128	41,382
fbc530 Units	0.69	1.39	2.08	2.78	4.16	5.55
Capital Cost($ K)	30,145	47,962	62,933	76,311	100,131	121,417
Annualized($ K):						
Capital	6,330	10,072	13,216	16,025	21,028	25,498
Operating	3,091	4,918	6,454	7,825	10,268	12,451
Total	9,422	14,990	19,669	23,851	31,296	37,948

NOTE: Excludes fuel and de-sulphurization.

Even before de-sulphurization costs, the annualization costs of natural gas-fired facilities are from one-quarter to one-third of the PCF and FBC facilities. It is quite clear that on the basis of

capital and operating costs alone that natural gas fired facilities are very much preferred. The smaller module size possible with natural gas also permits a more gradual growth in project size. The incremental steps are smaller. Therefore, the whole incentive for consideration of solid fuel steam generators at Lindbergh must fall on fuel cost savings.

Detailed cost summary tables for coal and coke by source are contained in Appendix II for comparison purposes.

8.2.2 Delivered Fuel Costs

In the selection of least-cost fuels, it is the cost of generated steam that must be minimized. Table 8.2 shows the fuel consumption, fuel costs at source and delivered, as well as the cost of steam per unit of fuel consumed. These steam costs include the capital and operating facilities charges plus any de-sulphurization costs incurred. As the volume of solid fuel demand grows with scale of operations, the transportation modes run the expected sequence from truck (at low volumes) through rail and then pipeline at the highest volumes.

Detailed cost summary tables for coal and coke by source are contained in Appendix II for comparison purposes.

For coal, the delivered cost at low tonnages is almost 250% of the mine gate price. At higher tonnages, the deliverd cost drops to about 160% of the mine gate price. Transportation costs forms a much smaller portion of the cost of coke delivered from Lloydminster to Lindbergh at low volumes such that the delivered cost starts at bout 131% of stockpile values and decreases to about 128% at highest volumes. On the heat content basis, both coal and coke can be delivered to Lindbergh for less than $1/GJ at the highest volumes of consumption in this study.

Table 8.2

FUEL COST COMPARISON

Lindbergh

PRODUCTION						
Oil(m3/day)	800	1,600	2,400	3,200	4,800	6,400
Steam(K m3/year)	1,080	2,161	3,241	4,322	6,482	8,643
FUEL CONSUMED(TJ/y)	2,739	5,478	8,217	10,957	16,435	21,913
NATURAL GAS:						
Combustion Mode	gas190	gas190	gas190	gas190	gas190	gas190
Consumed(MM m3/y)	73.6	147.2	220.7	294.3	441.5	588.6
Price($/K m3)	93.54	93.54	93.54	93.54	93.54	93.54
Unit Steam Costs:						
$/GJ (gas)	3.44	3.33	3.27	3.23	3.19	3.16
$/K m3 (gas)	128.15	123.79	121.62	120.30	118.72	117.73
$/m3 (steam)	8.73	8.43	8.28	8.19	8.08	8.02
COAL:						
Source	Camrose	Camrose	Camrose	Camrose	Camrose	Camrose
Transport Mode	Truck	Truck	Truck	Unitrain	Pipeline	Pipeline
Combustion Mode	fbc530	fbc530	fbc530	fbc530	fbc530	fbc530
HeatContent(GJ/T)	18.30	18.30	18.30	18.30	18.30	18.30
Consumed(K T/y)	149.7	299.4	449.0	598.7	898.1	1,197.4
Price($/T):						
F.O.B. Source	11.15	11.15	11.15	11.15	11.15	11.15
Delivered	26.74	25.09	24.48	22.41	19.53	17.87
Unit Steam Costs:						
$/GJ (coal)	4.90	4.11	3.73	3.40	2.97	2.71
$/Tonne (coal)	89.68	75.16	68.29	62.24	54.38	49.56
$/m3 (steam)	12.42	10.41	9.46	8.62	7.53	6.87
COKE:						
Source	Lloydmin	Lloydmin	Lloydmin	Lloydmin	Lloydmin	Lloydmin
Transport Mode	Truck	Truck	Truck	Truck	Truck	Unitrain
Combustion Mode	fbc530	fbc530	fbc530	fbc530	fbc530	fbc530
HeatContent(GJ/T)	29.86	29.86	29.86	29.86	29.86	29.86
Consumed(K T/y)	91.7	183.5	275.2	366.9	550.4	733.9
Price($/T):						
F.O.B. Source	20.00	20.00	20.00	20.00	20.00	20.00
Delivered	26.22	26.13	26.07	26.03	25.97	25.58
Unit Steam Costs:						
$/GJ (coke)	4.40	3.70	3.35	3.13	2.86	2.67
$/Tonne (coke)	131.42	110.34	100.04	93.52	85.33	79.79
$/m3 (steam)	11.16	9.37	8.49	7.94	7.24	6.77

NOTE: Includes de-sulphurization.

8.2.3 Cost of Steam

One of the economic objectives of alternative fuels is to generate steam at lower cost than natural gas at the crude production location. At Lindbergh, coal fuelled steam generators meet the natural gas fuelled cost of steam at 3,902 m^3/d (24,540 BOPD) of crude production. Coke from Lloydminster does not begin to compete with gas until crude production exceeds 2,765 m^3/d (17,390 BOPD). With capital charges included, the cost of steam at Lindbergh is about 15 to 20% of the market value of the produced crude.

The costs of steam on an annual basis are summarized in Table 8.3. The cost of steam per unit of steam injected is graphically presented in Figure 8.2 which also includes lease crude (at $125.80/m^3 or

Table 8.3

ANNUAL COST OF STEAM
($ 000)

Lindbergh

PRODUCTION						
Oil(m3/day)	800	1,600	2,400	3,200	4,800	6,400
Steam(K m3/year)	1,080	2,161	3,241	4,322	6,482	8,643
NATURAL GAS						
Capital Charges:						
Transportation	77	155	232	309	464	618
Site Facilities	1,376	2,498	3,540	4,534	6,426	8,229
Total	1,454	2,652	3,772	4,843	6,889	8,847
Operating Costs:						
Transportation	2	4	6	7	11	15
Site Facilities	1,090	1,794	2,419	3,024	4,213	5,374
Total	1,092	1,798	2,425	3,031	4,224	5,389
Fuel Costs	6,883	13,766	20,648	27,531	41,297	55,062
Steam Cost: Total	9,429	18,216	26,845	35,405	52,409	69,299
$/m3	8.73	8.43	8.28	8.19	8.08	8.02
COAL						
Source	Camrose	Camrose	Camrose	Camrose	Camrose	Camrose
Transport Mode	Truck	Truck	Truck	Unitrain	Pipeline	Pipeline
Combustion Mode	fbc530	fbc530	fbc530	fbc530	fbc530	fbc530
Capital Charges:						
Transportation	410	410	410	2,050	0	0
Site Facilities	6,330	10,072	13,216	16,025	21,028	25,498
Total	6,740	10,482	13,625	18,075	21,028	25,498
Operating Costs:						
Transportation	1,924	3,765	5,579	4,692	7,531	8,053
Site Facilities	3,091	4,918	6,454	7,825	10,268	12,451
Total	5,015	8,683	12,033	12,517	17,799	20,504
Fuel Costs	1,668	3,337	5,005	6,673	10,010	13,347
Steam Cost: Total	13,424	22,501	30,663	37,266	48,837	59,348
$/m3	12.42	10.41	9.46	8.62	7.53	6.87
COKE						
Source	Lloydmin	Lloydmin	Lloydmin	Lloydmin	Lloydmin	Lloydmin
Transport Mode	Truck	Truck	Truck	Truck	Truck	Unitrain
Combustion Mode	fbc530	fbc530	fbc530	fbc530	fbc530	fbc530
Capital Charges:						
Transportation	0	0	0	0	0	1,882
Site Facilities	6,330	10,072	13,216	16,025	21,028	25,498
Total	6,330	10,072	13,216	16,025	21,028	27,379
Operating Costs:						
Transportation	571	1,125	1,671	2,211	3,285	2,216
Site Facilities	3,320	5,376	7,141	8,742	11,642	14,283
Total	3,891	6,502	8,812	10,953	14,927	16,500
Fuel Costs	1,835	3,669	5,504	7,339	11,008	14,677
Steam Cost: Total	12,056	20,243	27,532	34,317	46,963	58,556
$/m3	11.16	9.37	8.49	7.94	7.24	6.77

$20/bbl) as an alternative fuel at net market value. The high fixed annual capital service charges associated with solid fuels fall rapidly per unit of steam, as the volume of crude production rises. At the lower production levels, it is apparent from Figure

8.2 that natural gas is the preferred steam generator fuel. At 800 m^3/d neither coal nor coke can even compete with lease crude. Above 800 m^3/d, both coal and coke overcome lease crude, but only coke meets the natural gas fired cost of steam at 2,765 m^3/d.

Figure 8.2

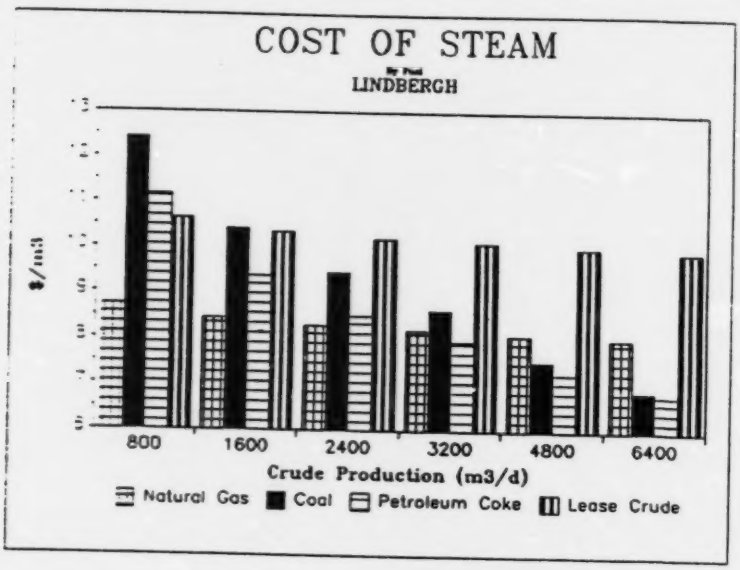
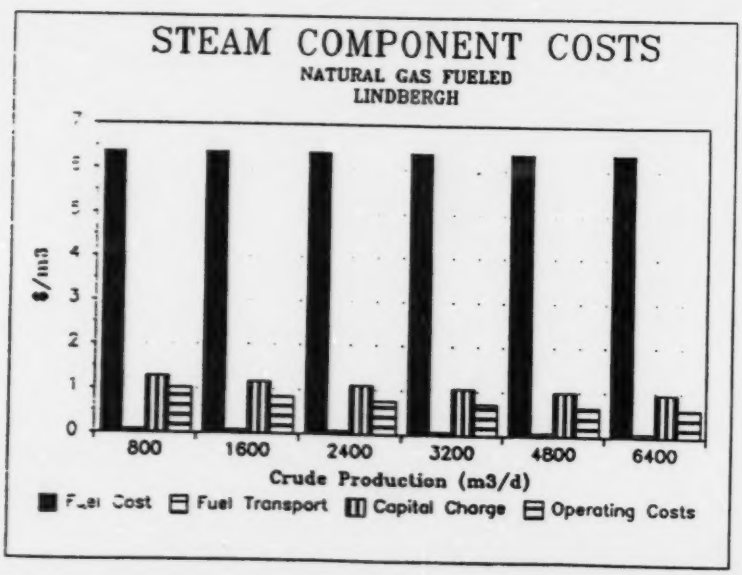
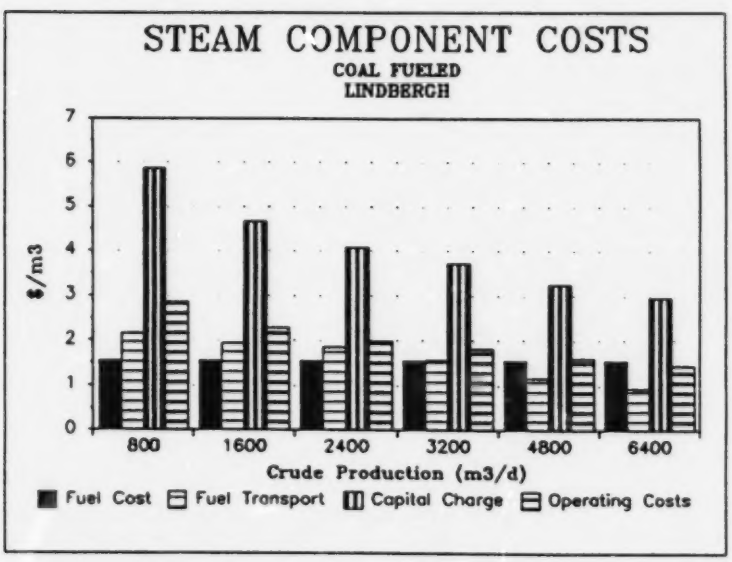


Figure 8.3



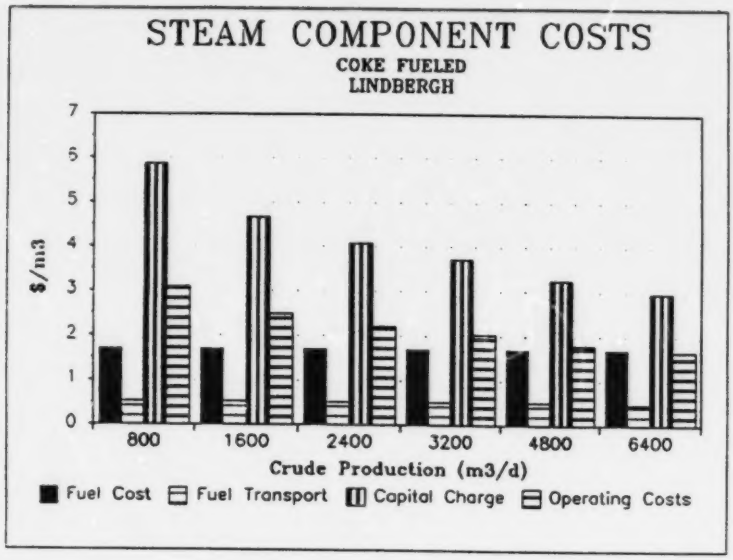
Figures 8.3 to 8.5 show the component costs of a unit of steam injected at Lindbergh. For natural-gas-fired steam the capital charges are a relatively flat function of production level and are dominated by the fuel costs at about $6.37/m^3$ (steam). Fuel costs for coke and coal, at source, are in the order of $1.50/m^3$ (steam) but with quantity dependent transportation charges for coal ranging from $2.16/m^3$ (steam) down to $0.93/m^3$ (steam). Figures 8.3 and 8.5 graphically depict the large capital service component of steam cost associated with solid fuels. This drops by a factor of two for coal from the low quantity end ($5.86/m^3$) to the high quantity end of Figure 8.4 ($2.95/m^3$).

Figure 8.4



Coke, using FBC technology, enjoys the same economies of scale unimpaired by the higher de-sulphurization costs.

Figure 8.5



8.2.4 Differential Economics

The differential economics of alternative fuels at Lindbergh are more positive for the alternative fuels than the utility approach to costing steam as shown in Tables 8.4 and 8.5 and Figures 8.6 and 8.7. Because of the annual operating cost savings realized even at the lowest production levels, both coal and coke show positive "real" (constant dollar) rates of return even at 1,600 m^3/d (10,000 BOPD) and pay back the additional investment above that required for natural gas within the expected project life.

Table 8.4

DIFFERENTIAL ECONOMICS*
COAL - NATURAL GAS
($ 000)

Lindbergh

OIL PRODUCTION(m3/d)	800	1,600	2,400	3,200	4,800	6,400
ALTERNATE FUEL:						
Source	Camrose	Camrose	Camrose	Camrose	Camrose	Camrose
Transport Mode	Truck	Truck	Truck	Unitrain	Pipeline	Pipeline
Combustion Mode	fbc530	fbc530	fbc530	fbc530	fbc530	fbc530
CAPITAL DIFFERENCE						
Transportation**	1,582	1,214	846	8,288	-2,207	-2,943
Site Facilities	23,591	36,067	46,075	54,721	69,533	82,230
Total	25,173	37,281	46,921	63,010	67,326	79,287
OPERATING DIFFERENCE						
Transportation	1,922	3,761	5,574	4,685	7,520	8,039
Site Facilities	2,001	3,124	4,034	4,802	6,055	7,076
Fuel Cost	-5,214	-10,429	-15,643	-20,858	-31,287	-41,716
Total	-1,291	-3,544	-6,035	-11,372	-17,711	-26,601
ECONOMIC PARAMETERS						
Payback(years)	19.49	10.52	7.77	5.54	3.80	2.98
IRR(%) ***	0.2%	7.1%	11.4%	17.3%	26.1%	33.4%
NPV at 9%	-13,385	-4,933	8,173	40,798	94,351	163,540
12%	-15,528	-10,813	-1,840	21,931	64,967	119,406
15%	-17,090	-15,101	-9,144	8,170	43,534	87,216

* Includes de-sulphurization.
** Pipelines are assumed to be owned by outside investors.
*** Discount rates do not include the inflation rate.

Table 8.5

DIFFERENTIAL ECONOMICS*
COKE - NATURAL GAS
($ 000)

Lindbergh

OIL PRODUCTION(m3/d)	800	1,600	2,400	3,200	4,800	6,400
ALTERNATE FUEL:						
Source	Lloydmin	Lloydmin	Lloydmin	Lloydmin	Lloydmin	Lloydmin
Transport Mode	Truck	Truck	Truck	Truck	Truck	Unitrain
Combustion Mode	fbc530	fbc530	fbc530	fbc530	fbc530	fbc530
CAPITAL DIFFERENCE						
Transportation**	-368	-736	-1,104	-1,472	-2,207	6,017
Site Facilities	23,591	36,067	46,075	54,721	69,533	82,230
Total	23,223	35,331	44,971	53,250	67,326	88,247
OPERATING DIFFERENCE						
Transportation	569	1,122	1,665	2,204	3,274	2,202
Site Facilities	2,230	3,582	4,722	5,718	7,430	8,909
Fuel Cost	-5,048	-10,096	-15,144	-20,193	-30,289	-40,385
Total	-2,250	-5,392	-8,757	-12,271	-19,585	-29,274
ECONOMIC PARAMETERS						
Payback(years)	10.32	6.55	5.14	4.34	3.44	3.01
IRR(%) ***	7.3%	14.2%	18.9%	22.7%	28.9%	33.1%
NPV at 9%	-2,687	13,891	34,970	58,766	111,459	178,986
12%	-6,419	4,945	20,441	38,407	78,965	130,417
15%	-9,142	-1,580	9,844	23,558	55,264	94,992

* Includes de-sulphurization.
** Pipelines are assumed to be owned by outside investors.
*** Discount rates do not include the inflation rate.

Figure 8.6

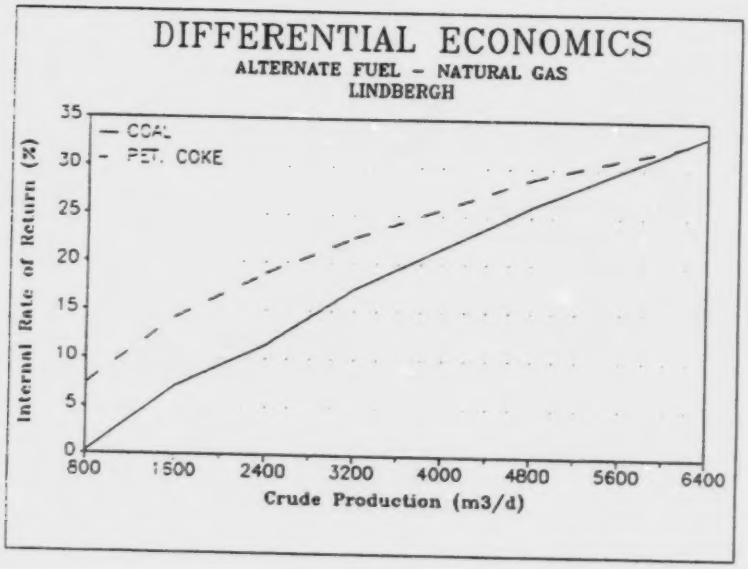
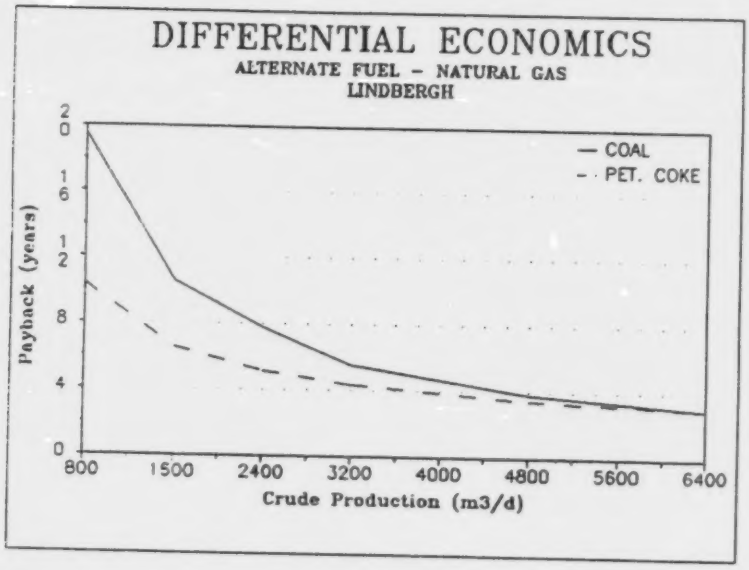


Figure 8.7



8.2.5 Gas Equivalent Capital Costs

In addition to cost of steam and differential economics, a third method of alternative fuel comparison with natural gas is to compare capital costs yielding the same cost of steam. These comparisons for

coal and coke are made in Table 8.6 and Figures 8.8 and 8.9. This is again an accounting point-in-time approach that provides a more conservative comparison than that indicated by the project-life differential DCF economics. Nevertheless, at the highest production level, coal can suffer only a 5% capital cost over-run at Lindbergh and still produce steam at equal utility cost to natural gas. Coke, on the same basis, has a cushion of only 7% even at the highest production level.

Table 8.6

GAS EQUIVALENT CAPITAL COSTS*
($ 000)

Lindbergh

OIL PRODUCTION(m3/d)	800	1,600	2,400	3,200	4,800	6,400
COAL:						
Source	Camrose	Camrose	Camrose	Camrose	Camrose	Camrose
Transport Mode	Truck	Truck	Truck	Unitrain	Pipeline	Pipeline
Combustion Mode	fbc530	fbc530	fbc530	fbc530	fbc530	fbc530
Steam Generators	0.69	1.39	2.08	2.78	4.16	5.55
Capital Cost:						
Equivalent	17,362	34,251	50,717	70,359	111,562	153,254
Estimated	30,145	47,962	62,933	76,311	100,131	121,417
Difference	-12,782	-13,711	-12,216	-5,952	11,431	31,837
Unit Cost:						
Equivalent	25,015	24,673	24,357	25,342	26,789	27,600
Estimated	43,430	34,550	30,223	27,486	24,044	21,866
Difference	-18,416	-9,877	-5,867	-2,144	2,745	5,734
COKE:						
Source	Lloydmin	Lloydmin	Lloydmin	Lloydmin	Lloydmin	Lloydmin
Transport Mode	Truck	Truck	Truck	Truck	Truck	Truck
Combustion Mode	fbc530	fbc530	fbc530	fbc530	fbc530	fbc530
Steam Generators	0.69	1.39	2.08	2.78	4.16	5.55
Capital Cost:						
Equivalent	21,739	41,475	60,736	79,794	117,558	155,788
Estimated	30,145	47,962	62,933	76,311	100,131	121,417
Difference	-8,406	-6,487	-2,197	3,483	17,427	34,371
Unit Cost:						
Equivalent	31,320	29,878	29,168	28,741	28,229	28,056
Estimated	43,430	34,550	30,223	27,486	24,044	21,866
Difference	-12,110	-4,673	-1,055	1,254	4,185	6,190

* De-sulphurization capital excluded.

Figure 8.8

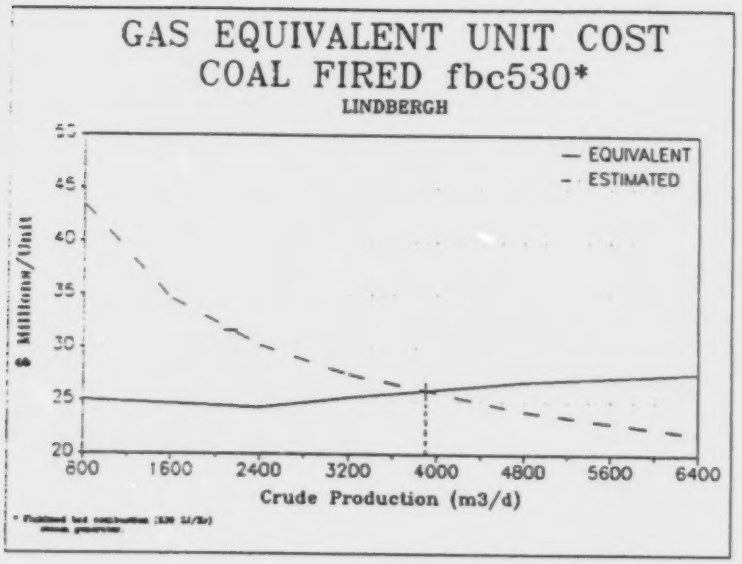
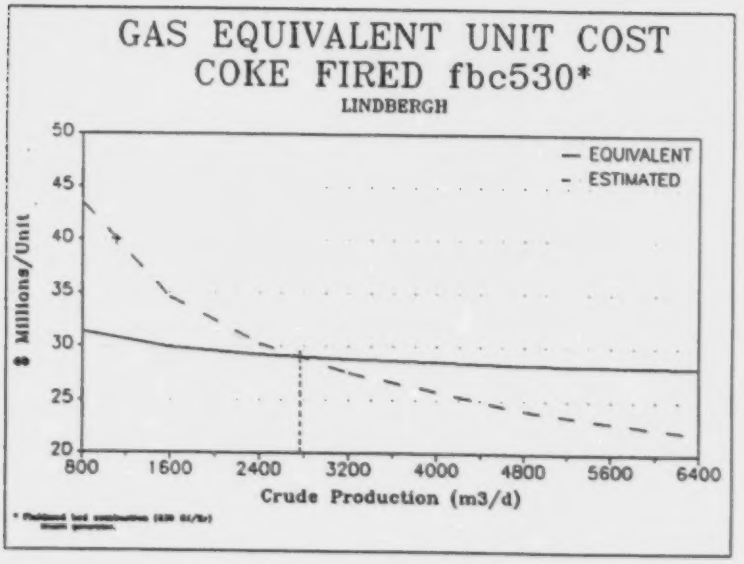


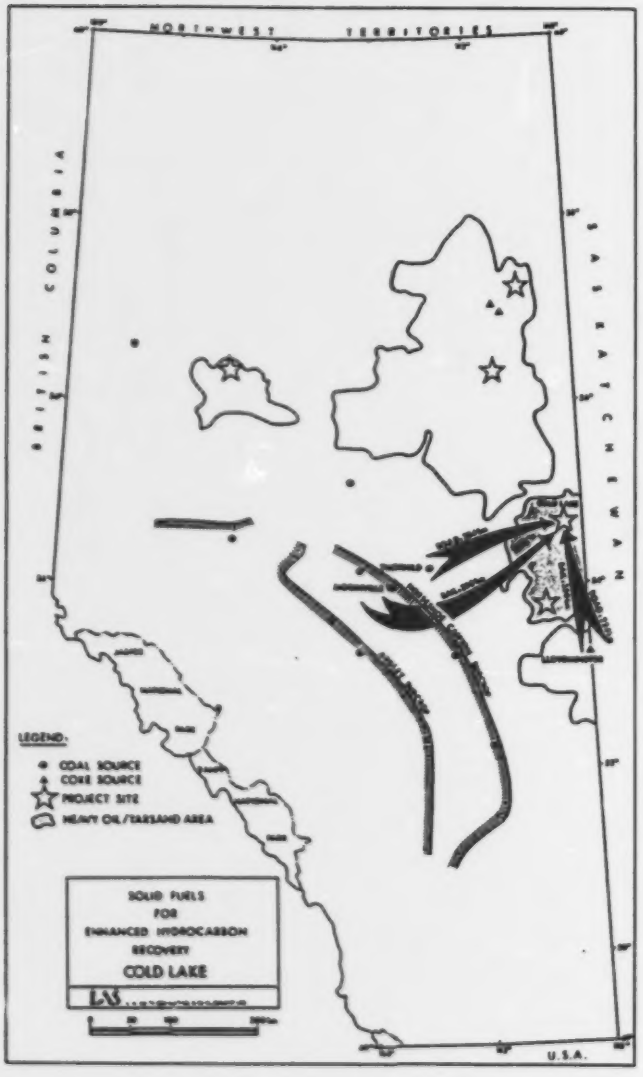
Figure 8.9



8.3 Cold Lake

The location and logistics of the Cold Lake producing area and selected site are illustrated in Figure 8.10.

Figure 8.10



8.3.2 Site Facilities

The lower steam/oil ratio assumed for Cold Lake (3.0) than for Lindbergh (3.7) lowers the facilities requirements correspondingly. Table 8.7 presents the steam generator capital and operating costs (ex fuel) by combustion mode for Cold Lake. Again, on the basis of capital and operating costs alone, natural gas fired steam generating facilities have a large advantage over solid fuels.

Table 8.7

STEAM CAPITAL & OPERATING COSTS

Cold Lake

STEAM GENERATION PARAMETERS						
Steam/Oil Ratio(m3/m3)	3.00					
Steam Heat Content(GJ/m3)	2.15					
PRODUCTION						
Oil(m3/day)	800	1,600	2,400	3,200	4,800	6,400
Steam(K m3/year)	876	1,752	2,628	3,504	5,256	7,008
FUEL CONSUMED(TJ/y)	2,221	4,442	6,663	8,884	13,326	17,767
COMBUSTION MODE:						
gas190 Units	1.48	2.97	4.45	5.93	8.90	11.86
Capital Cost($ K)	5,472	9,932	14,076	18,027	25,548	32,720
Annualized($ K):						
Capital	1,149	2,086	2,956	3,786	5,365	6,871
Operating	935	1,543	2,069	2,567	3,541	4,498
Total	2,084	3,629	5,025	6,353	8,906	11,369
pcf530 Units	0.56	1.13	1.69	2.25	3.38	4.50
Capital Cost($ K)	28,710	45,680	59,939	72,680	95,367	115,640
Annualized($ K):						
Capital	6,029	9,593	12,587	15,263	20,027	24,284
Operating	2,298	3,656	4,798	5,818	7,634	9,256
Total	8,327	13,249	17,385	21,081	27,661	33,541
fbc370 Units	0.81	1.61	2.42	3.22	4.84	6.45
Capital Cost($ K)	28,563	45,446	59,632	72,308	94,879	115,048
Annualized($ K):						
Capital	5,998	9,544	12,523	15,185	19,925	24,160
Operating	2,929	4,660	6,115	7,415	9,729	11,798
Total	8,927	14,204	18,638	22,600	29,654	35,958
fbc530 Units	0.56	1.13	1.69	2.25	3.38	4.50
Capital Cost($ K)	26,193	41,675	54,683	66,308	87,005	105,500
Annualized($ K):						
Capital	5,501	8,752	11,484	13,925	18,271	22,155
Operating	2,686	4,274	5,608	6,800	8,922	10,819
Total	8,186	13,025	17,091	20,724	27,193	32,974

NOTE: Excludes fuel and de-sulphurization.

8.3.2 Delivered Fuel Costs

Thorhild and Morinville are competitively close together as least-cost coal sources for the Cold Lake

location. The transportation modes, for solid fuels, run the expected sequence from truck (at low volumes) to unit-train (at high volumes). The road and rail routes are sufficiently direct to eliminate pipeline as a cost competitive transport mode for coal to Cold Lake. Again, the delivered cost of coal drops by about 20% from the lowest requirements ($27.46/tonne at 131,300 tonnes/year) to the highest requirements tested ($22.20/tonne at 955,200 tonnes/year) as shown in Table 8.3. These coal costs correspond to $1.62/GJ down to $1.20/GJ of heating value.

Table 8.3

FUEL COST COMPARISON

Cold Lake

PRODUCTION						
Oil(m3/day)	800	1,600	2,400	3,200	4,800	6,400
Steam(K m3/year)	876	1,752	2,628	3,504	5,256	7,008
FUEL CONSUMED(TJ/y)	2,221	4,442	6,663	8,884	13,326	17,767
NATURAL GAS:						
Combustion Mode	gas190	gas190	gas190	gas190	gas190	gas190
Consumed(MM m3/y)	59.7	119.3	179.0	238.6	357.9	477.3
Price($/K m3)	93.54	93.54	93.54	93.54	93.54	93.54
Unit Steam Costs:						
$/GJ (gas)	3.48	3.36	3.30	3.26	3.21	3.18
$/K m3 (gas)	129.56	125.04	122.70	121.24	119.50	118.44
$/m3 (steam)	8.82	8.52	8.36	8.26	8.14	8.07
COAL:						
Source	Thorhild	Thorhild	Thorhild	Thorhild	Morinvll	Morinvll
Transport Mode	Truck	Truck	Truck	Unitrain	Unitrain	Unitrain
Combustion Mode	fbc530	fbc530	fbc530	fbc530	fbc530	fbc530
HeatContent(GJ/T)	17.00	17.00	17.00	17.00	18.60	18.60
Consumed(K T/y)	130.6	261.3	391.9	522.6	716.4	955.2
Price($/T):						
F.O.B. Source	13.58	13.58	13.58	13.58	11.70	11.70
Delivered	27.48	27.26	27.12	26.13	23.75	22.28
Unit Steam Costs:						
$/GJ (coal)	5.30	4.54	4.16	3.87	3.32	3.05
$/Tonne (coal)	90.15	77.11	70.72	65.79	61.71	56.80
$/m3 (steam)	13.44	11.50	10.55	9.81	8.41	7.74
COKE:						
Source	Lloydmin	Lloydmin	Lloydmin	Lloydmin	Lloydmin	Lloydmin
Transport Mode	Truck	Truck	Truck	Truck	Truck	Truck
Combustion Mode	fbc530	fbc530	fbc530	fbc530	fbc530	fbc530
HeatContent(GJ/T)	29.86	29.86	29.86	29.86	29.86	29.86
Consumed(K T/y)	74.4	148.8	223.1	297.5	446.3	595.0
Price($/T):						
F.O.B. Source	20.00	20.00	20.00	20.00	20.00	20.00
Delivered	34.04	33.87	33.74	33.63	33.49	33.41
Unit Steam Costs:						
$/GJ (coke)	4.91	4.15	3.78	3.54	3.25	3.06
$/Tonne (coke)	146.60	123.93	112.83	105.79	96.92	91.32
$/m3 (steam)	12.45	10.52	9.58	8.98	8.23	7.75

NOTE: Includes de-sulphurization.

The least cost coke source for Cold Lake is again Lloydminster. On a delivered basis, the cost of coke decreases by about 25% from the lowest requirements ($34.04/tonne at 74,400 tonnes/year) to the highest requirements ($33.41/tonne at 595,000 tonnes/year). These coke costs correspond to $1.14/GJ down to $1.12/GJ.

8.3.3 Cost of Steam

At Cold Lake, Table 8.9 shows that coal fuelled steam generators provide steam at the same

Table 8.9

ANNUAL COST OF STEAM
($ 000)

Cold Lake

PRODUCTION						
Oil(m3/day)	800	1,600	2,400	3,200	4,800	6,400
Steam(K m3/year)	876	1,752	2,628	3,504	5,256	7,008
NATURAL GAS						
Capital Charges:						
Transportation	63	125	188	251	376	501
Site Facilities	1,149	2,086	2,956	3,786	5,365	6,871
Total	1,212	2,211	3,144	4,036	5,741	7,372
Operating Costs:						
Transportation	1	3	4	6	9	12
Site Facilities	935	1,543	2,069	2,567	3,541	4,498
Total	937	1,546	2,073	2,573	3,550	4,510
Fuel Costs	5,581	11,161	16,742	22,323	33,484	44,645
Steam Cost: Total	7,729	14,919	21,959	28,932	42,775	56,527
$/m3	8.82	8.52	8.36	8.26	8.14	8.07
COAL						
Source	Thorhild	Thorhild	Thorhild	Thorhild	Morinvll	Morinvll
Transport Mode	Truck	Truck	Truck	Unitrain	Unitrain	Unitrain
Combustion Mode	fbc530	fbc530	fbc530	fbc530	fbc530	fbc530
Capital Charges:						
Transportation	0	0	0	2,100	2,100	2,100
Site Facilities	5,501	8,752	11,484	13,925	18,271	22,155
Total	5,501	8,752	11,484	16,025	20,371	24,255
Operating Costs:						
Transportation	1,817	3,575	5,303	4,458	6,534	8,000
Site Facilities	2,686	4,274	5,608	6,800	8,922	10,819
Total	4,503	7,848	10,913	11,258	15,456	18,819
Fuel Costs	1,774	3,548	5,322	7,096	8,385	11,180
Steam Cost: Total	11,777	20,148	27,719	34,379	44,211	54,254
$/m3	13.44	11.50	10.55	9.81	8.41	7.74
COKE						
Source	Lloydmin	Lloydmin	Lloydmin	Lloydmin	Lloydmin	Lloydmin
Transport Mode	Truck	Truck	Truck	Truck	Truck	Truck
Combustion Mode	fbc530	fbc530	fbc530	fbc530	fbc530	fbc530
Capital Charges:						
Transportation	0	0	0	0	0	0
Site Facilities	5,501	8,752	11,484	13,925	18,271	22,155
Total	5,501	8,752	11,484	13,925	18,271	22,155
Operating Costs:						
Transportation	1,044	2,063	3,065	4,056	6,021	7,977
Site Facilities	2,872	4,645	6,165	7,542	10,036	12,304
Total	3,916	6,708	9,230	11,599	16,058	20,282
Fuel Costs	1,488	2,975	4,463	5,950	8,925	11,900
Steam Cost: Total	10,904	18,435	25,176	31,474	43,254	54,337
$/m3	12.45	10.52	9.58	8.98	8.23	7.75

cost as gas-fired steam generators ($8.11/m^3$) at 5,520 m^3/d (34,720 BOPD) of crude production. At 6,400 m^3/d (40,000 BOPD) of crude production, coal-raised steam averages $7.74/m^3$ while natural gas-raised steam averages $8.07/m^3$, a difference of $0.33/m^3$ on an utility costing (accounting or "book") basis.

In the case of coke, a steam-cost cross-over with natural gas does not occur until 4,000 m^3/d at $8.23/m^3$ (steam). Even at 6,400 m^3/d of crude production, coke-raised steam is $7.75/m^3$, a saving of only $0.32/m^3$ from gas-raised steam at $8.07/m^3$.

The above differences are illustrated in Figures 8.11 to 8.14. These graphs again emphasize the capital cost versus fuel saving trade-off between the natural gas and solid fuel options.

Figure 8.11

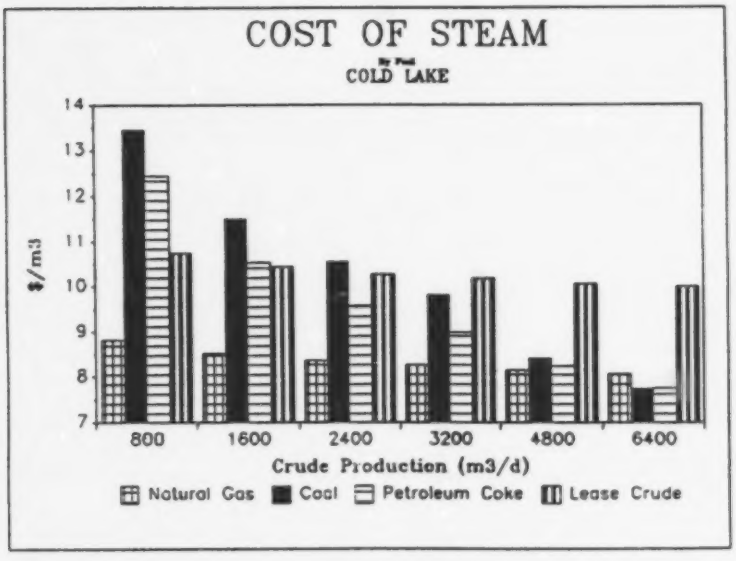


Figure 8.12

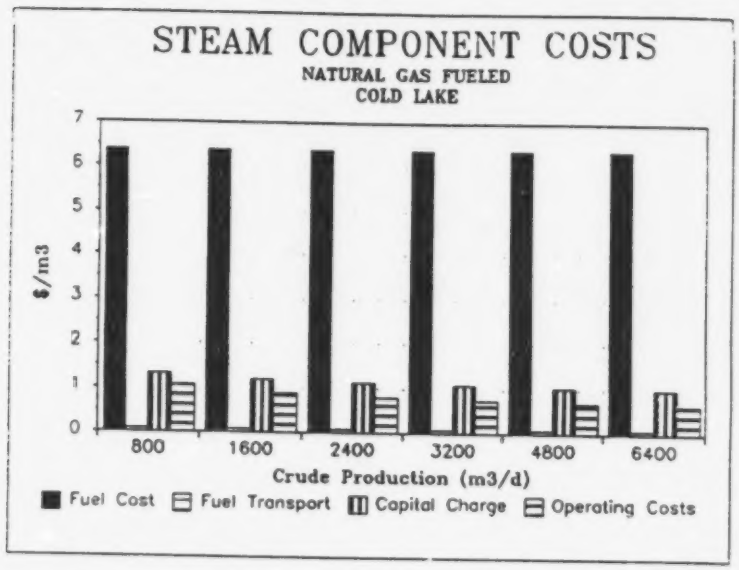


Figure 8.13

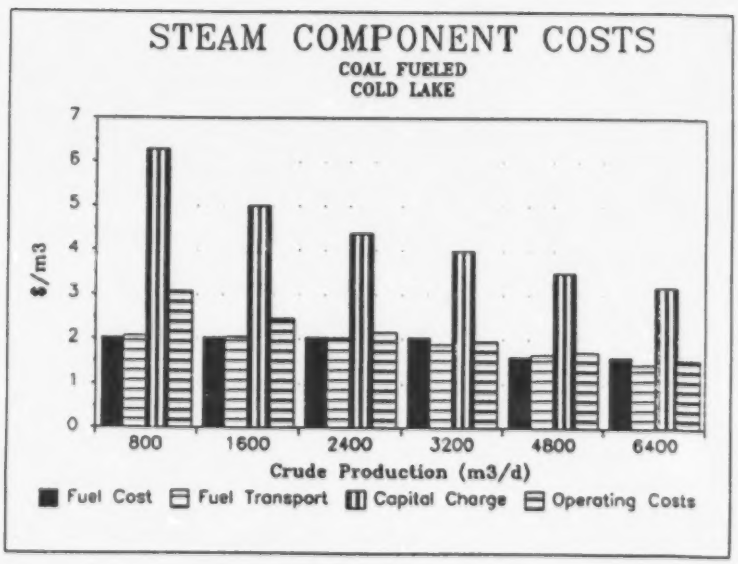
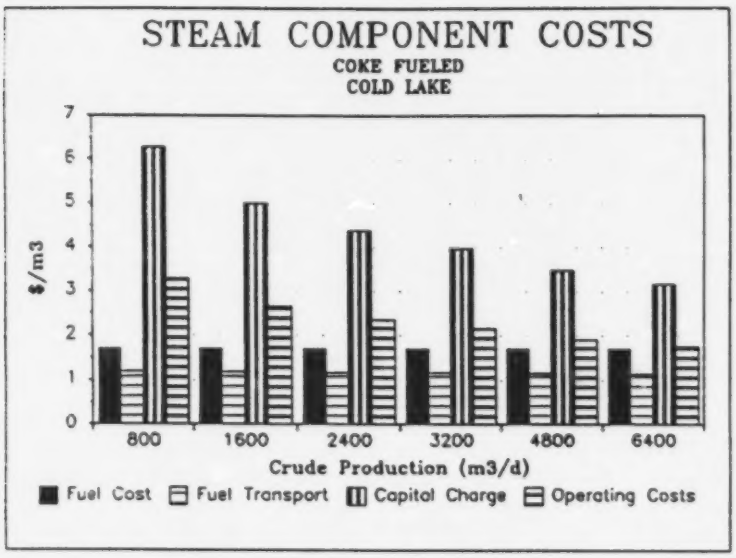


Figure 8.14



8.3.4 Differential Economics

The economic benefits of solid fuels are a positive function of steam/oil ratio. However, the higher steam/oil ratio at Cold Lake as compared to Lindbergh is nearly offset by the effects of higher transportation costs such that the differential economics are very similar between the two locations. Tables 8.10 and 8.11 and Figures 8.15 and 8.16 present the differential economics for Cold Lake. Again, the DCF approach indicates much more positive economics for solid fuels than the accounting approach. On a DCF basis, coal begins to look competitive with natural gas at Cold Lake at 3,200 m^3/d (20,000 BOPD). Coke reaches a similar rate of return at 2,400 m^3/d (15,000 BOPD) of crude production. At each production level above 800 m^3/d, the economics for coke at Cold Lake are better than those for coal, assuming a Lloydminster supply at competitive prices.

Table 8.10

DIFFERENTIAL ECONOMICS*
COAL - NATURAL GAS
($ 000)

Cold Lake

OIL PRODUCTION(m3/d)	800	1,600	2,400	3,200	4,800	6,400
ALTERNATE FUEL:						
Source	Thorhild	Thorhild	Thorhild	Thorhild	Morinvll	Morinvll
Transport Mode	Truck	Truck	Truck	Unitrain	Unitrain	Unitrain
Combustion Mode	fbc530	fbc530	fbc530	fbc530	fbc530	fbc530
CAPITAL DIFFERENCE						
Transportation**	-298	-597	-895	8,807	8,210	7,614
Site Facilities	20,721	31,743	40,607	48,281	61,457	72,781
Total	20,423	31,146	39,713	57,088	69,667	80,394
OPERATING DIFFERENCE						
Transportation	1,815	3,572	5,301	4,452	6,525	7,989
Site Facilities	1,751	2,730	3,539	4,232	5,381	6,321
Fuel Cost	-3,807	-7,613	-11,420	-15,226	-25,099	-33,465
Total	-241	-1,311	-2,580	-6,542	-13,193	-19,156
ECONOMIC PARAMETERS						
Payback(years)	84.86	23.75	15.39	8.73	5.28	4.20
IRR(%) ***	-11.0%	-1.6%	2.6%	9.6%	18.3%	23.5%
NPV at 9%	-18,226	-19,176	-16,159	2,629	50,768	94,475
12%	-18,625	-21,352	-20,440	-8,224	28,879	62,692
15%	-18,916	-22,939	-23,563	-16,141	12,914	39,511

* Includes de-sulphurization.
** Pipelines are assumed to be owned by outside investors.
*** Discount rates do not include the inflation rate.

Table 8.11

DIFFERENTIAL ECONOMICS*
COKE - NATURAL GAS
($ 000)

Cold Lake

OIL PRODUCTION(m3/d)	800	1,600	2,400	3,200	4,800	6,400
ALTERNATE FUEL:						
Source	Lloydmin	Lloydmin	Lloydmin	Lloydmin	Lloydmin	Lloydmin
Transport Mode	Truck	Truck	Truck	Truck	Truck	Truck
Combustion Mode	fbc530	fbc530	fbc530	fbc530	fbc530	fbc530
CAPITAL DIFFERENCE						
Transportation**	-298	-597	-895	-1,193	-1,790	-2,386
Site Facilities	20,721	31,743	40,607	48,281	61,457	72,781
Total	20,423	31,146	39,713	47,088	59,667	70,394
OPERATING DIFFERENCE						
Transportation	1,043	2,060	3,061	4,050	6,012	7,965
Site Facilities	1,937	3,102	4,096	4,975	6,496	7,807
Fuel Cost	-4,093	-8,186	-12,279	-16,372	-24,558	-32,745
Total	-1,114	-3,025	-5,123	-7,347	-12,051	-16,973
ECONOMIC PARAMETERS						
Payback(years)	18.33	10.30	7.75	6.41	4.95	4.15
IRR(%) ***	0.8%	7.4%	11.4%	14.6%	19.6%	23.8%
NPV at 9%	-10,253	-3,536	7,051	19,978	50,337	84,542
12%	-12,101	-8,555	-1,448	7,789	30,344	56,383
15%	-13,449	-12,215	-7,647	-1,102	15,762	35,844

* Includes de-sulphurization.
** Pipelines are assumed to be owned by outside investors.
*** Discount rates do not include the inflation rate.

Figure 8.15

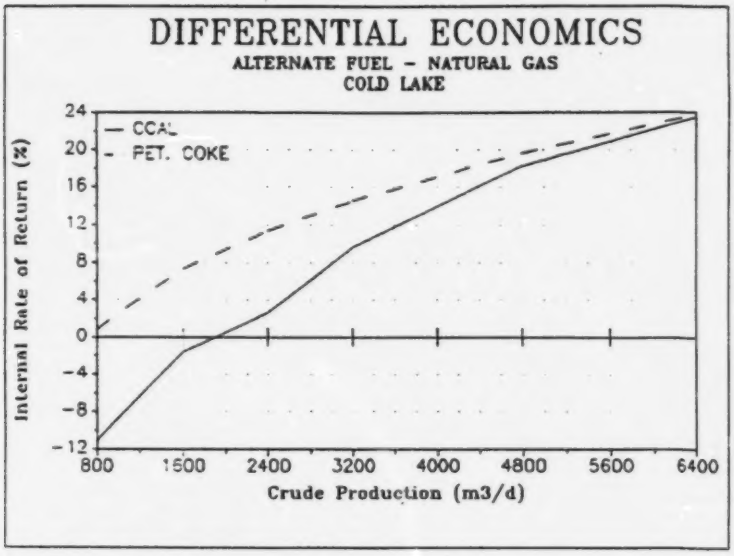
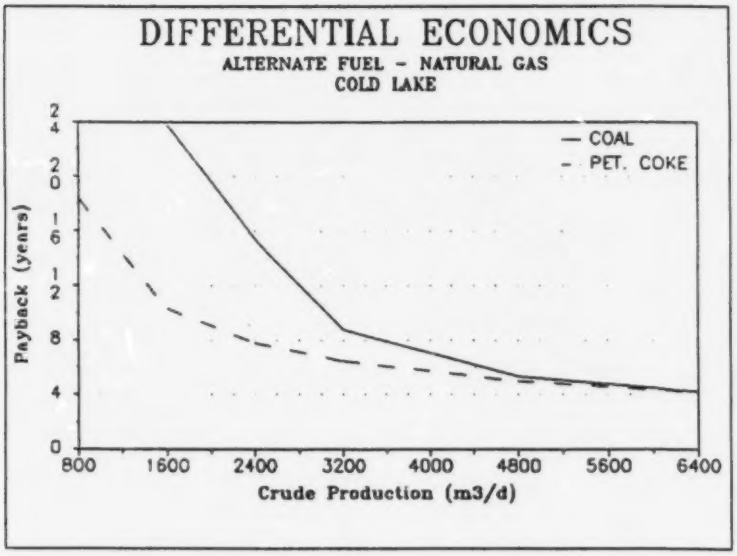


Figure 8.16



8.3.5 Gas Equivalent Capital Costs

The gas equivalent capital costs for coal at Cold Lake are much lower than those at Lindbergh.

Coke, also suffers from the higher transportation costs from Lloydminster to the Cold Lake location. These results are presented in Table 8.12 and are illustrated in Figures 8.17 and 8.18. The "cross-over" point for coal occurs at 5,531 m^3/d (34,790 BOPD) of crude production. Similarly, the "cross-over" point for coke occurs at 5,161 m^3/d (32,463 BOPD). At 5,400 m^3/d, the coal facilities could incur a cost over-run of 5.8% and still provide steam at the natural gas-fired generator cost. The coke facilities, on the other hand, could bear a corresponding 6.6% cost over-run and remain competitive.

Table 8.12

GAS EQUIVALENT CAPITAL COSTS*
($ 000)

	Cold Lake					
OIL PRODUCTION(m3/d)	800	1,600	2,400	3,200	4,800	6,400
COAL:						
Source	Thorhild	Thorhild	Thorhild	Thorhild	Morinvll	Morinvll
Transport Mode	Truck	Truck	Truck	Unitrain	Unitrain	Unitrain
Combustion Mode	fbc530	fbc530	fbc530	fbc530	fbc530	fbc530
Steam Generators	0.56	1.13	1.69	2.25	3.38	4.50
Capital Cost:						
Equivalent	13,241	24,943	36,256	48,881	82,408	112,775
Estimated	26,193	41,675	54,683	66,308	87,005	105,500
Difference	-12,952	-16,732	-18,428	-17,427	-4,597	7,274
Unit Cost:						
Equivalent	23,528	22,161	21,474	21,714	24,405	25,049
Estimated	46,543	37,026	32,389	29,456	25,767	23,433
Difference	-23,015	-14,865	-10,915	-7,741	-1,362	1,616
COKE:						
Source	Lloydmin	Lloydmin	Lloydmin	Lloydmin	Lloydmin	Lloydmin
Transport Mode	Truck	Truck	Truck	Truck	Truck	Truck
Combustion Mode	fbc530	fbc530	fbc530	fbc530	fbc530	fbc530
Steam Generators	0.56	1.13	1.69	2.25	3.38	4.50
Capital Cost:						
Equivalent	16,035	30,425	44,391	58,176	85,471	112,507
Estimated	26,193	41,675	54,683	66,308	87,005	105,500
Difference	-10,158	-11,250	-10,292	-8,132	-1,534	7,007
Unit Cost:						
Equivalent	28,493	27,031	26,293	25,843	25,312	24,989
Estimated	46,543	37,026	32,389	29,456	25,767	23,433
Difference	-18,049	-9,995	-6,096	-3,612	-454	1,556

* De-sulphurization capital excluded.

Figure 8.17

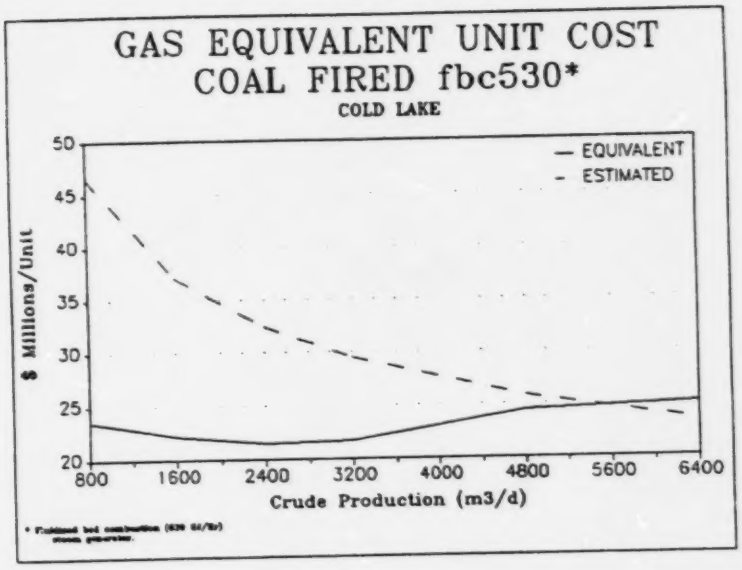
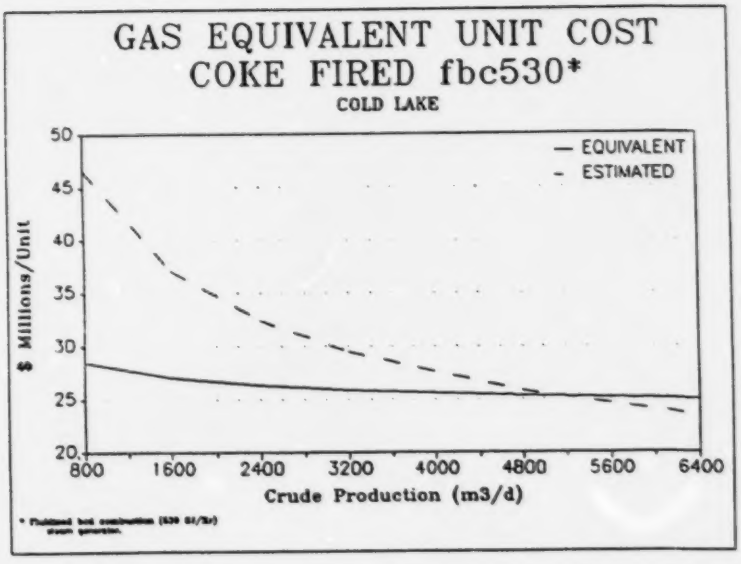


Figure 8.18

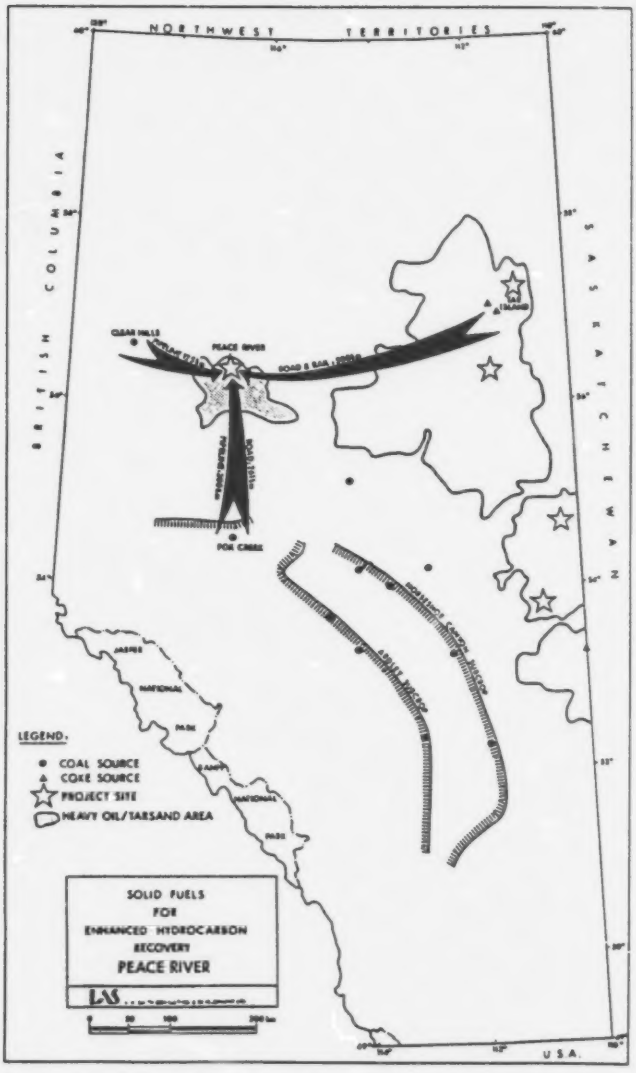


8.4 Peace River

The location and logistics of the Peace River producing area and selected site are illustrated in Figure 8.19.

Figure 8.19

Peace River - Project Site



8.4.1 Site Facilities

At a steam/oil ratio of 4.0, the steam generator facilities requirements at Peace River are more than those of Lindbergh and Cold Lake. Table 8.13 presents the derived facilities capital and operating costs (ex fuel) by combustion mode for Peace River. The observations made for Lindbergh and Cold Lake regarding the costs apply similarly to Peace River.

Table 8.13

STEAM CAPITAL & OPERATING COSTS

Peace River

STEAM GENERATION PARAMETERS						
Steam/Oil Ratio(m3/m3)	4.00					
Steam Heat Content(GJ/m3)	2.15					
PRODUCTION						
Oil(m3/day)	800	1,600	2,400	3,200	4,800	6,400
Steam(K m3/year)	1,168	2,336	3,504	4,672	7,008	9,344
FUEL CONSUMED(TJ/y)	2,961	5,922	8,884	11,845	17,767	23,690
STEAM GENERATORS:						
gas190 Units	1.98	3.95	5.93	7.91	11.86	15.81
Capital Cost($ K)	7,008	12,720	18,027	23,087	32,720	41,904
Annualized($ K):						
Capital	1,472	2,671	3,786	4,848	6,871	8,800
Operating	1,154	1,898	2,567	3,218	4,498	5,745
Total	2,626	4,569	6,353	8,067	11,369	14,545
pcf530 Units	0.75	1.50	2.25	3.00	4.50	6.00
Capital Cost($ K)	34,813	55,390	72,680	88,130	115,640	140,222
Annualized($ K):						
Capital	7,311	11,632	15,263	18,507	24,284	29,447
Operating	2,787	4,434	5,818	7,054	9,256	11,224
Total	10,097	16,066	21,081	25,562	33,541	40,671
fbc370 Units	1.07	2.15	3.22	4.30	6.45	8.60
Capital Cost($ K)	34,635	55,107	72,308	87,679	115,048	139,504
Annualized($ K):						
Capital	7,273	11,572	15,185	18,413	24,160	29,296
Operating	3,552	5,651	7,415	8,991	11,798	14,305
Total	10,825	17,223	22,600	27,404	35,958	43,601
fbc530 Units	0.75	1.50	2.25	3.00	4.50	6.00
Capital Cost($ K)	31,761	50,534	66,308	80,403	105,500	127,927
Annualized($ K):						
Capital	6,670	10,612	13,925	16,885	22,155	26,865
Operating	3,257	5,182	6,800	8,245	10,819	13,118
Total	9,927	15,794	20,724	25,130	32,974	39,983

NOTE: Excludes fuel and de-sulphurization.

8.4.2 Delivered Fuel Costs

Both Clear Hills and Fox Creek are very close together in the costs of coal supply to Peace River. Table 8.14 shows the switch in sources in the attempt to minimize the cost of steam. Because of the amount of new rail construction required to haul the coal, pipeline becomes the economic mode of coal transportation at relatively low volumes (740,000 tonnes/year). Nevertheless, the delivered coal energy value ranges from $2.05/GJ down to $1.23/GJ with increasing production levels.

Table 8.14

FUEL COST COMPARISON

Peace River

PRODUCTION						
Oil(m3/day)	800	1,600	2,400	3,200	4,800	6,400
Steam(K m3/year)	1,168	2,336	3,504	4,672	7,008	9,344
FUEL CONSUMED(TJ/y)	2,961	5,922	8,884	11,845	17,767	23,690
NATURAL GAS:						
Combustion Mode	gas190	gas190	gas190	gas190	gas190	gas190
Consumed(MM m3/y)	79.5	159.1	238.6	318.2	477.3	636.3
Price($/K m3)	93.54	93.54	93.54	93.54	93.54	93.54
Unit Steam Costs:						
$/GJ (gas)	3.43	3.31	3.26	3.22	3.18	3.16
$/K m3 (gas)	127.63	123.34	121.24	119.97	118.44	117.48
$/m3 (steam)	8.69	8.40	8.26	8.17	8.07	8.00
COAL:						
Source	Fox Crk.	Fox Crk.	Fox Crk.	ClearHls	Fox Crk.	Fox Crk.
Transport Mode	Truck	Truck	Truck	Pipeline	Pipeline	Pipeline
Combustion Mode	fbc530	fbc530	fbc530	fbc530	fbc530	fbc530
HeatContent(GJ/T)	16.10	16.10	16.10	16.00	16.10	16.10
Consumed(K T/y)	183.9	367.9	551.8	740.3	1,103.6	1,471.4
Price($/T):						
F.O.B. Source	10.45	10.45	10.45	15.30	10.45	10.45
Delivered	33.00	29.32	28.03	24.92	21.38	19.76
Unit Steam Costs:						
$/GJ (coal)	5.40	4.49	4.07	3.68	3.18	2.91
$/Tonne (coal)	86.97	72.25	65.59	58.87	51.26	46.93
$/m3 (steam)	13.70	11.38	10.33	9.33	8.07	7.39
COKE:						
Source	Tar Isl.	Tar Isl.	Tar Isl.	Tar Isl.	Tar Isl.	Tar Isl.
Transport Mode	Truck	Truck	Truck	Truck	Unitrain	Unitrain
Combustion Mode	fbc530	fbc530	fbc530	fbc530	fbc530	fbc530
HeatContent(GJ/T)	33.50	33.50	33.50	33.50	33.50	33.50
Consumed(K T/y)	88.4	176.8	265.2	353.6	530.4	707.2
Price($/T):						
F.O.B. Source	17.25	17.25	17.25	17.25	17.25	17.25
Delivered	62.05	61.46	61.01	60.68	49.04	46.23
Unit Steam Costs:						
$/GJ (coke)	5.37	4.67	4.32	4.10	3.49	3.24
$/Tonne (coke)	179.99	156.43	144.80	137.39	116.85	108.41
$/m3 (steam)	13.62	11.84	10.96	10.40	8.84	8.20

NOTE: Includes de-sulphurization.

Without a pipeline option, coke transportation to Peace River is very expensive. No direct transportation link with the Athabasca coke sources currently exists. Therefore the cost of the long haul virtually removes coke from the fuel competition at Peace River.

8.4.3 Cost of Steam

Table 8.15 shows that the average estimated cost of steam-raised from natural gas is about $8/m^3$ (steam) at Peace River. Coal meets the cost of

Table 8.15

ANNUAL COST OF STEAM
($ 000)

Peace River

PRODUCTION						
Oil(m3/day)	800	1,600	2,400	3,200	4,800	6,400
Steam(K m3/year)	1,168	2,336	3,504	4,672	7,008	9,344
NATURAL GAS						
Capital Charges:						
Transportation	84	167	251	334	501	668
Site Facilities	1,472	2,671	3,786	4,848	6,871	8,800
Total	1,555	2,838	4,036	5,182	7,372	9,468
Operating Costs:						
Transportation	2	4	6	8	12	16
Site Facilities	1,154	1,898	2,567	3,218	4,498	5,745
Total	1,156	1,902	2,573	3,226	4,510	5,761
Fuel Costs	7,441	14,882	22,323	29,763	44,645	59,527
Steam Cost: Total	10,152	19,622	28,932	38,172	56,527	74,755
$/m3	8.69	8.40	8.26	8.17	8.07	8.00
COAL						
Source	Fox Crk.	Fox Crk.	Fox Crk.	ClearHls	Fox Crk.	Fox Crk.
Transport Mode	Truck	Truck	Truck	Pipeline	Pipeline	Pipeline
Combustion Mode	fbc530	fbc530	fbc530	fbc530	fbc530	fbc530
Capital Charges:						
Transportation	1,197	1,197	1,197	0	0	0
Site Facilities	6,670	10,612	13,925	16,885	22,155	26,865
Total	7,867	11,809	15,122	16,885	22,155	26,865
Operating Costs:						
Transportation	2,951	5,743	8,503	7,126	12,064	13,690
Site Facilities	3,257	5,182	6,800	8,245	10,819	13,118
Total	6,208	10,925	15,303	15,371	22,883	26,808
Fuel Costs	1,922	3,845	5,767	11,325	11,534	15,378
Steam Cost: Total	15,997	26,578	36,191	43,580	56,572	69,051
$/m3	13.70	11.38	10.33	9.33	8.07	7.39
COKE						
Source	Tar Isl.	Tar Isl.	Tar Isl.	Tar Isl.	Tar Isl.	Tar Isl.
Transport Mode	Truck	Truck	Truck	Truck	Unitrain	Unitrain
Combustion Mode	fbc530	fbc530	fbc530	fbc530	fbc530	fbc530
Capital Charges:						
Transportation	0	0	0	0	0	0
Site Facilities	6,670	10,612	13,925	16,885	22,155	26,865
Total	6,670	10,612	13,925	16,885	22,155	26,865
Operating Costs:						
Transportation	3,960	7,815	11,605	15,356	16,858	20,495
Site Facilities	3,755	6,179	8,295	10,239	13,810	17,107
Total	7,716	13,994	19,900	25,595	30,668	37,602
Fuel Costs	1,525	3,050	4,574	6,099	9,149	12,198
Steam Cost: Total	15,911	27,656	38,399	48,579	61,972	76,665
$/m3	13.62	11.84	10.96	10.40	8.84	8.20

gas-raised steam, $3.07/m^3$, at a production level of 4,800 m^3/d (30,000 BOPD). At 6,400 m^3/d of such production, the costs of coal-raised steam drops to $7.39/m^3$. Because of the high transportation costs, coke never does compete with natural gas or coal at the production levels considered. These results are presented in detail in Table 8.15 and Figures 8.22 to 8.25.

Figure 8.20

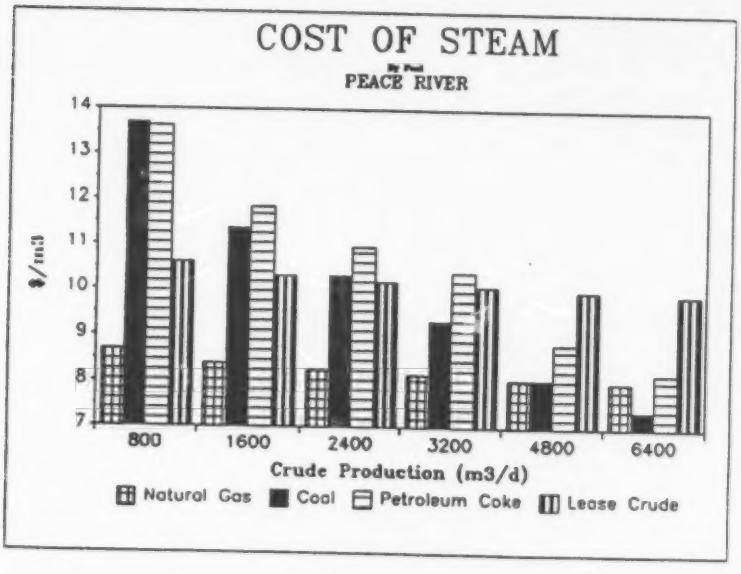


Figure 8.21

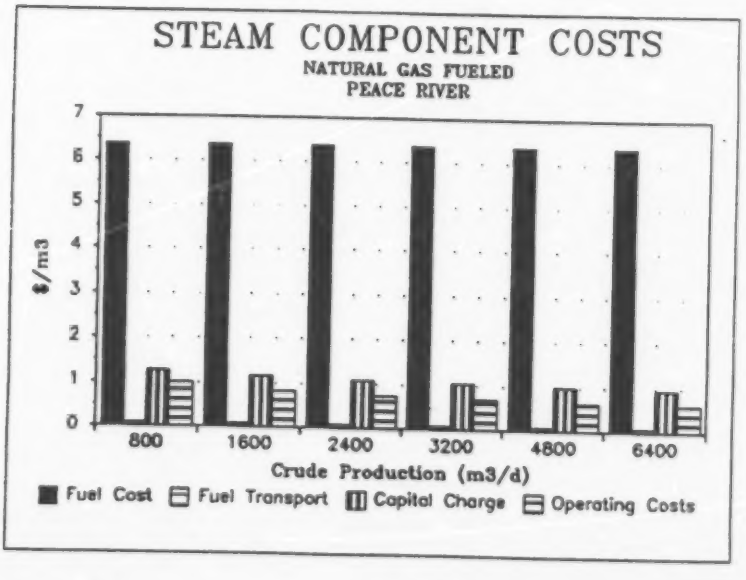


Figure 8.22

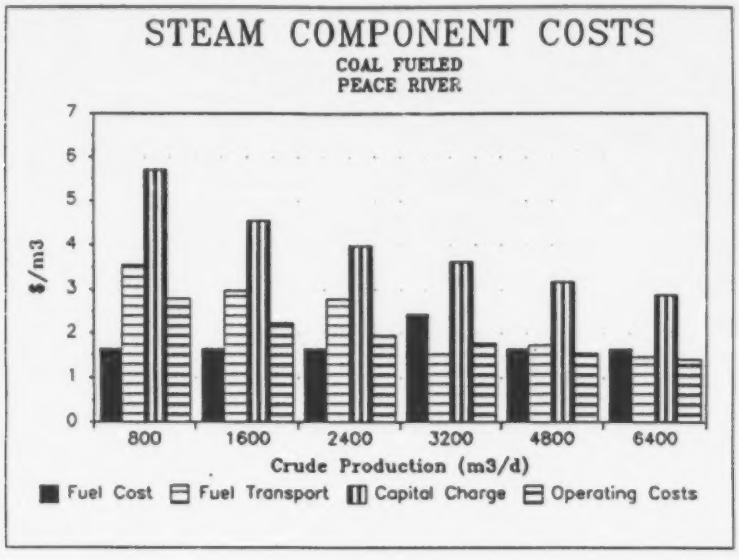
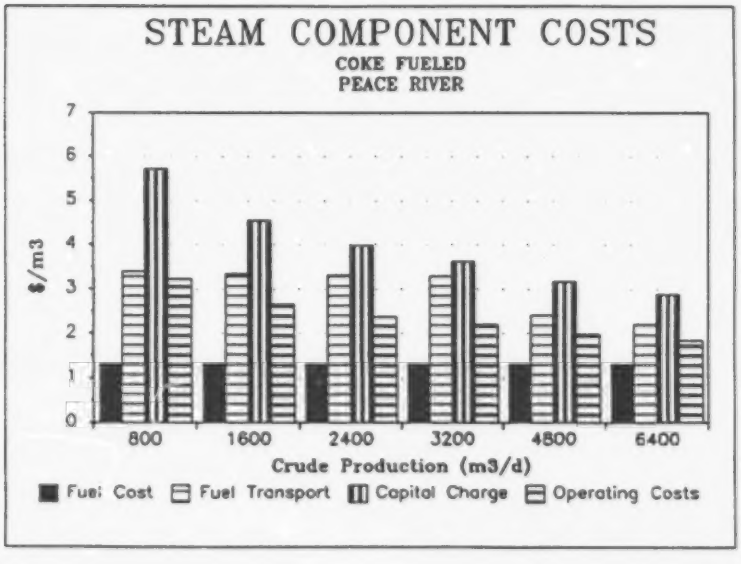


Figure 8.23



8.4.4 Differential Economics

Tables 8.16 and 8.17 and Figures 8.24 and 8.25 present the differential economics for Peace River. Coal just becomes competitive with natural gas, on a

Table 8.16

DIFFERENTIAL ECONOMICS*
COAL - NATURAL GAS
($ 000)

Peace River

OIL PRODUCTION(m3/d)	800	1,600	2,400	3,200	4,800	6,400
ALTERNATE FUEL:						
Source	Fox Crk.	Fox Crk.	Fox Crk.	ClearHls	Fox Crk:	Fox Crk.
Transport Mode	Truck	Truck	Truck	Pipeline	Pipeline	Pipeline
Combustion Mode	fbc530	fbc530	fbc530	fbc530	fbc530	fbc530
CAPITAL DIFFERENCE						
Transportation**	5,302	4,905	4,507	-1,591	-2,386	-3,182
Site Facilities	24,753	37,814	48,281	57,316	72,781	86,023
Total	30,055	42,719	52,788	55,725	70,394	82,841
OPERATING DIFFERENCE						
Transportation	2,949	5,739	8,497	7,118	12,052	13,674
Site Facilities	2,103	3,284	4,232	5,027	6,321	7,374
Fuel Cost	-5,519	-11,037	-16,556	-18,439	-33,111	-44,148
Total	-467	-2,015	-3,826	-6,294	-14,738	-23,101
ECONOMIC PARAMETERS						
Payback(years)	64.41	21.20	13.80	8.85	4.78	3.59
IRR(%) ***	-9.2%	-0.6%	3.8%	9.4%	20.4%	27.7%
NPV at 9%	-25,795	-24,328	-17,861	1,728	64,146	128,034
12%	-26,570	-27,671	-24,209	-8,714	39,693	89,708
15%	-27,134	-30,109	-28,839	-16,330	21,858	61,753

* Includes de-sulphurization.
** Pipelines are assumed to be owned by outside investors.
*** Discount rates do not include the inflation rate.

Table 8.17

DIFFERENTIAL ECONOMICS*
COKE - NATURAL GAS
($ 000)

Peace River

OIL PRODUCTION(m3/d)	800	1,600	2,400	3,200	4,800	6,400
ALTERNATE FUEL:						
Source	Tar Isl.	Tar Isl.	Tar Isl.	Tar Isl.	Tar Isl.	Tar Isl.
Transport Mode	Truck	Truck	Truck	Truck	Unitrain	Unitrain
Combustion Mode	fbc530	fbc530	fbc530	fbc530	fbc530	fbc530
CAPITAL DIFFERENCE						
Transportation**	-398	-795	-1,193	-1,591	-2,386	-3,182
Site Facilities	24,753	37,814	48,281	57,316	72,781	86,023
Total	24,355	37,019	47,088	55,725	70,394	82,841
OPERATING DIFFERENCE						
Transportation	3,958	7,811	11,599	15,348	16,846	20,479
Site Facilities	2,602	4,281	5,728	7,021	9,312	11,362
Fuel Cost	-5,916	-11,832	-17,748	-23,664	-35,496	-47,328
Total	644	260	-421	-1,295	-9,338	-15,487
ECONOMIC PARAMETERS						
Payback(years)	-37.82	-142.43	111.73	43.03	7.54	5.35
IRR(%) ***	0.0%	0.0%	-12.7%	-6.4%	11.9%	18.0%
NPV at 9%	-30,234	-39,391	-43,241	-43,905	14,847	58,535
12%	-29,166	-38,960	-43,940	-46,053	-646	32,840
15%	-28,386	-38,645	-44,450	-47,620	-11,946	14,099

* Includes de-sulphurization.
** Pipelines are assumed to be owned by outside investors.
*** Discount rates do not include the inflation rate.

ROR basis, at about 3,200 m^3/d (20,000 BOPD), assuming a "real" cut-off rate of return of 10%. Despite a large transportation cost penalty over natural gas and coal, coke reaches economic competitiveness at Peace River at 4,800 m^3/d (30,000 BOPD).

Figure 8.24

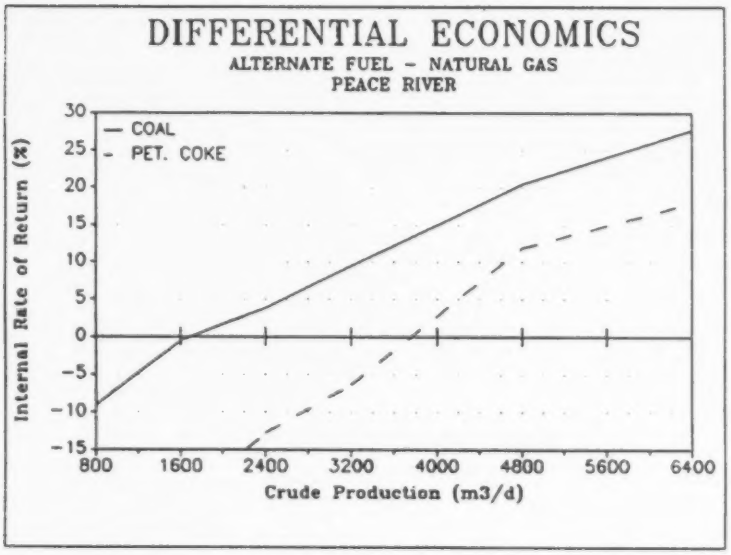
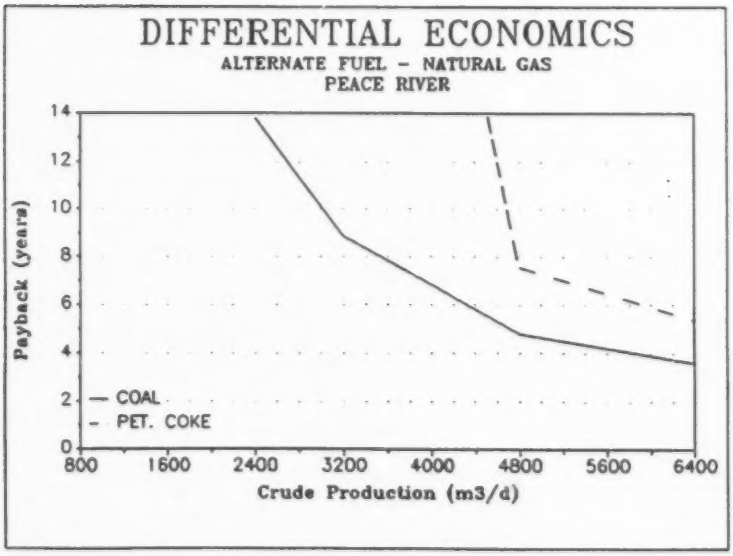


Figure 8.25



8.4.5 Gas Equivalent Capital Costs

Higher transportation costs dampen the economics for both coke and coal compared with more southerly locations. Nevertheless, coal reaches capital cost equivalency with natural gas at 4,817 m^3/d (30,300 BOPD). Coke does not reach capital cost equivalency under 5,400 m^3/d. These results are presented in Table 8.18 and Figures 8.26 and 8.27.

Table 8.18

GAS EQUIVALENT CAPITAL COSTS*
($ 000)

Peace River

OIL PRODUCTION(m3/d)	800	1,600	2,400	3,200	4,800	6,400
COAL:						
Source	Fox Crk.	Fox Crk.	Fox Crk.	Clearhls	Fox Crk.	Fox Crk.
Transport Mode	Truck	Truck	Truck	Pipeline	Pipeline	Pipeline
Combustion Mode	fbc530	fbc530	fbc530	fbc530	fbc530	fbc530
Steam Generators	0.75	1.50	2.25	3.00	4.50	6.00
Capital Cost:						
Equivalent	13,060	28,277	43,081	63,099	105,358	146,177
Estimated	31,761	50,534	66,308	80,403	105,500	127,927
Difference	-18,701	-22,257	-23,226	-17,305	-142	18,250
Unit Cost:						
Equivalent	17,405	18,842	19,138	21,023	23,402	24,351
Estimated	42,327	33,673	29,456	26,788	23,433	21,311
Difference	-24,923	-14,831	-10,318	-5,765	-32	3,040
COKE:						
Source	Tar Isl.	Tar Isl.	Tar Isl.	Tar Isl.	Tar Isl.	Tar Isl.
Transport Mode	Truck	Truck	Truck	Truck	Truck	Truck
Combustion Mode	fbc530	fbc530	fbc530	fbc530	fbc530	fbc530
Steam Generators	0.75	1.50	2.25	3.00	4.50	6.00
Capital Cost:						
Equivalent	13,336	24,830	36,018	47,104	88,079	121,818
Estimated	31,761	50,534	66,308	80,403	105,500	127,927
Difference	-18,425	-25,704	-30,290	-33,299	-17,421	-6,109
Unit Cost:						
Equivalent	17,773	16,545	16,000	15,694	19,564	20,293
Estimated	42,327	33,673	29,456	26,788	23,433	21,311
Difference	-24,555	-17,128	-13,456	-11,094	-3,870	-1,018

* De-sulphurization capital excluded.

Figure 8.26

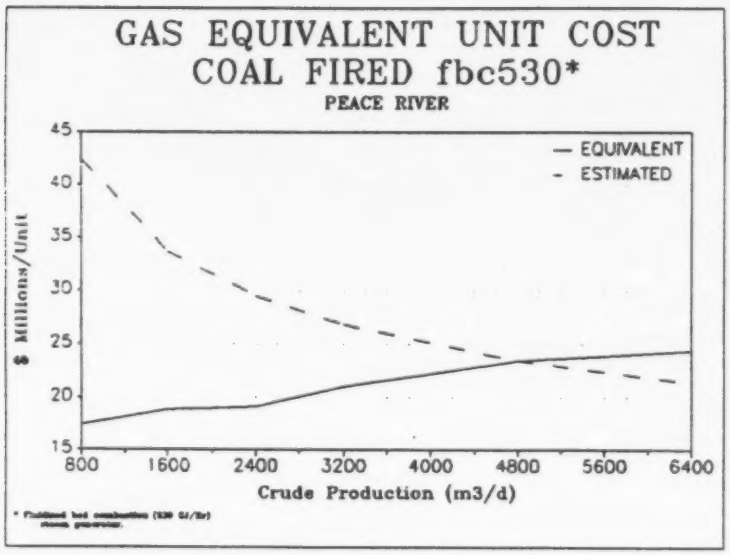
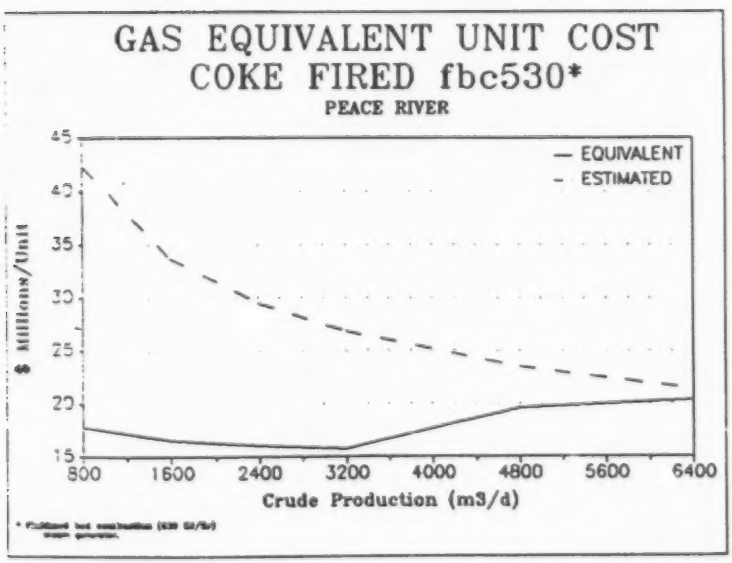


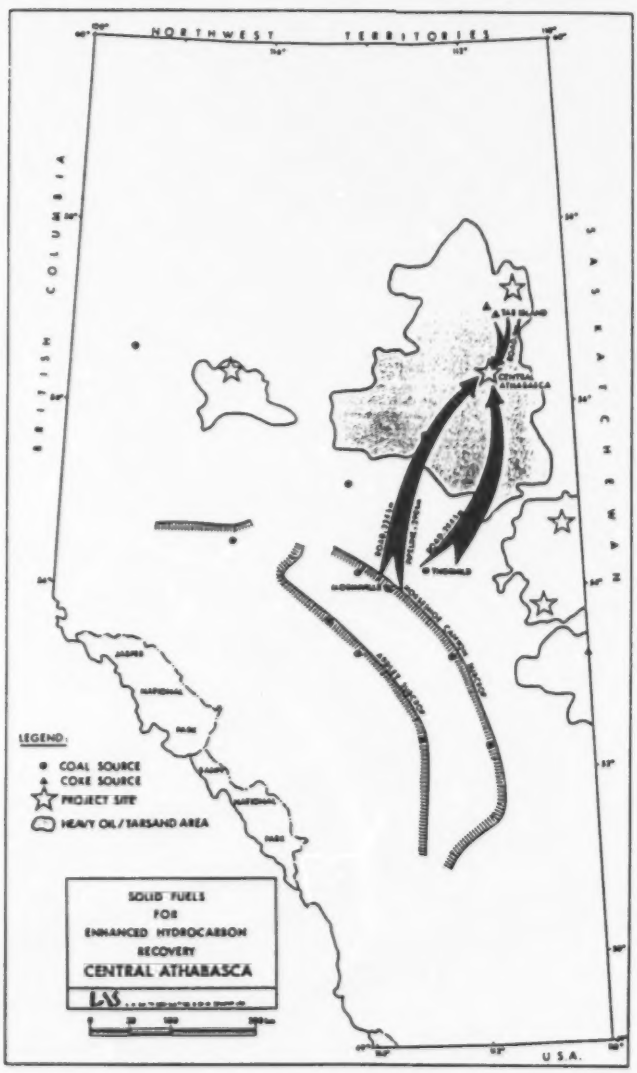
Figure 8.27



8.5 Central Athabasca

The location and logistics of the Central Athabasca producing area and selected site are illustrated in Figure 8.28.

Figure 8.28
Central Athabasca - Project Site



8.5.1 Site Facilities

At an assumed steam/oil ratio of 5.0, the corresponding steam generation facilities are shown in Table 8.19. Although the recovery process may be different from the other heavy oil areas, the facilities up to steam injection are assumed to be the same.

Table 8.19

STEAM CAPITAL & OPERATING COSTS

C.Athabasca

STEAM GENERATION PARAMETERS						
Steam/Oil Ratio(m3/m3)	5.00					
Steam Heat Content(GJ/m3)	2.15					
PRODUCTION						
Oil(m3/day)	800	1,600	2,400	3,200	4,800	6,400
Steam(K m3/year)	1,460	2,920	4,380	5,840	8,760	11,680
FUEL CONSUMED(TJ/y)	3,702	7,403	11,105	14,806	22,209	29,612
STEAM GENERATORS:						
gas190 Units	2.47	4.94	7.41	9.88	14.83	19.77
Capital Cost($ K)	8,491	15,411	21,841	27,971	39,642	50,769
Annualized($ K):						
Capital	1,783	3,236	4,587	5,874	8,325	10,662
Operating	1,355	2,237	3,056	3,862	5,436	6,956
Total	3,138	5,473	7,643	9,736	13,761	17,618
pcf530 Units	0.94	1.88	2.81	3.75	5.63	7.50
Capital Cost($ K)	40,427	64,323	84,401	102,342	134,288	162,834
Annualized($ K):						
Capital	8,490	13,508	17,724	21,492	28,200	34,195
Operating	3,236	5,149	6,756	8,192	10,749	13,034
Total	11,726	18,657	24,480	29,684	38,950	47,229
fbc370 Units	1.34	2.69	4.03	5.37	8.06	10.75
Capital Cost($ K)	40,220	63,993	83,969	101,818	133,600	162,000
Annualized($ K):						
Capital	8,446	13,439	17,633	21,382	28,056	34,020
Operating	4,124	6,562	8,611	10,441	13,700	16,612
Total	12,571	20,001	26,244	31,823	41,756	50,632
fbc530 Units	0.94	1.88	2.81	3.75	5.63	7.50
Capital Cost($ K)	36,883	58,683	77,001	93,369	122,514	148,557
Annualized($ K):						
Capital	7,745	12,323	16,170	19,608	25,728	31,197
Operating	3,782	6,018	7,896	9,575	12,563	15,234
Total	11,528	18,341	24,066	29,182	38,291	46,431

NOTE: Excludes fuel and de-sulphurization.

8.5.2 Delivered Fuel Costs

Morinville is the winning contender for coal supply to Central Athabasca over the whole range of coal supply. From the lowest to the highest production

levels, coal can be supplied to Central Athabasca from $1.88/GJ down to $1.33/GJ while coke costs range from $3.62/GJ down to $2.67/GJ. These costs in units of dollars per tonne are presented in Table 8.20.

Table 8.20

FUEL COST COMPARISON

C.Athabasca

PRODUCTION						
Oil(m3/day)	800	1,600	2,400	3,200	4,800	6,400
Steam(K m3/year)	1,460	2,920	4,380	5,840	8,760	11,680
FUEL CONSUMED(TJ/y)	3,702	7,403	11,105	14,806	22,209	29,612
NATURAL GAS:						
Combustion Mode	gas190	gas190	gas190	gas190	gas190	gas190
Consumed(MM m3/y)	99.4	198.9	298.3	397.7	596.6	795.4
Price($/K m3)	93.54	93.54	93.54	93.54	93.54	93.54
Unit Steam Costs:						
$/GJ (gas)	3.39	3.28	3.23	3.20	3.16	3.14
$/K m3 (gas)	126.18	122.14	120.24	119.10	117.69	116.77
$/m3 (steam)	8.59	8.32	8.19	8.11	8.01	7.95
COAL:						
Source	Morinvll	Morinvll	Morinvll	Morinvll	Morinvll	Morinvll
Transport Mode	Truck	Truck	Truck	Truck	Pipeline	Pipeline
Combustion Mode	fbc530	fbc530	fbc530	fbc530	fbc530	fbc530
HeatContent(GJ/T)	18.60	18.60	18.60	18.60	18.60	18.60
Consumed(K T/y)	199.0	398.0	597.0	796.0	1,194.0	1,592.1
Price($/T):						
F.O.B. Source	11.70	11.70	11.70	11.70	11.70	11.70
Delivered	33.49	32.33	31.88	31.66	26.73	24.82
Unit Steam Costs:						
$/GJ (coal)	4.91	4.22	3.88	3.67	3.16	2.90
$/Tonne (coal)	91.41	78.41	72.19	68.32	58.80	53.98
$/m3 (steam)	12.46	10.69	9.84	9.31	8.02	7.36
COKE:						
Source	Tar Isl.	Tar Isl.	Tar Isl.	Tar Isl.	Tar Isl.	Tar Isl.
Transport Mode	Truck	Truck	Truck	Truck	Truck	Truck
Combustion Mode	fbc530	fbc530	fbc530	fbc530	fbc530	fbc530
HeatContent(GJ/T)	33.50	33.50	33.50	33.50	33.50	33.50
Consumed(K T/y)	110.5	221.0	331.5	442.0	663.0	883.9
Price($/T):						
F.O.B. Source	17.25	17.25	17.25	17.25	17.25	17.25
Delivered	22.83	22.75	22.69	22.65	22.60	22.58
Unit Steam Costs:						
$/GJ (coke)	3.96	3.32	3.01	2.82	2.57	2.41
$/Tonne (coke)	132.80	111.38	100.93	94.31	86.00	80.75
$/m3 (steam)	10.05	8.43	7.64	7.14	6.51	6.11

NOTE: Includes de-sulphurization.

8.5.3 Cost of Steam

At Central Athabasca the coal-natural gas cross-over occurs at 4,827 m^3/d (30,360 BOPD) crude production. The corresponding cost of steam at the cross-over point is $8.01/$m^3$. As shown in Table 8.21, the cost of coal-raised steam drops to $7.36/$m^3$ at 6,400 m^3/d of production.

Table 8.21

ANNUAL COST OF STEAM
($ 000)

C.Athabasca

PRODUCTION						
Oil(m3/day)	800	1,600	2,400	3,200	4,800	6,400
Steam(K m3/year)	1,460	2,920	4,380	5,840	8,760	11,680
NATURAL GAS						
Capital Charges:						
Transportation	104	209	313	418	626	835
Site Facilities	1,783	3,236	4,587	5,874	8,325	10,662
Total	1,887	3,445	4,900	6,292	8,951	11,497
Operating Costs:						
Transportation	2	5	7	10	15	20
Site Facilities	1,355	2,237	3,056	3,862	5,436	6,956
Total	1,357	2,242	3,064	3,872	5,451	6,976
Fuel Costs	9,301	18,602	27,903	37,204	55,806	74,408
Steam Cost: Total	12,546	24,289	35,867	47,367	70,209	92,881
$/m3	8.59	8.32	8.19	8.11	8.01	7.95
COAL						
Source	Morinvll	Morinvll	Morinvll	Morinvll	Morinvll	Morinvll
Transport Mode	Truck	Truck	Truck	Truck	Pipeline	Pipeline
Combustion Mode	fbc530	fbc530	fbc530	fbc530	fbc530	fbc530
Capital Charges:						
Transportation	302	302	302	302	0	0
Site Facilities	7,745	12,323	16,170	19,608	25,728	31,197
Total	8,048	12,626	16,473	19,910	25,728	31,197
Operating Costs:						
Transportation	4,033	7,908	11,746	15,582	17,946	20,880
Site Facilities	3,782	6,018	7,896	9,575	12,563	15,234
Total	7,815	13,926	19,642	25,156	30,509	36,114
Fuel Costs	2,329	4,658	6,987	9,316	13,974	18,633
Steam Cost: Total	18,192	31,210	43,102	54,383	70,212	85,943
$/m3	12.46	10.69	9.84	9.31	8.02	7.36
COKE						
Source	Tar Isl.	Tar Isl.	Tar Isl.	Tar Isl.	Tar Isl.	Tar Isl.
Transport Mode	Truck	Truck	Truck	Truck	Truck	Truck
Combustion Mode	fbc530	fbc530	fbc530	fbc530	fbc530	fbc530
Capital Charges:						
Transportation	0	0	0	0	0	0
Site Facilities	7,745	12,323	16,170	19,608	25,728	31,197
Total	7,745	12,323	16,170	19,608	25,728	31,197
Operating Costs:						
Transportation	617	1,215	1,803	2,386	3,548	4,711
Site Facilities	4,405	7,264	9,766	12,067	16,302	20,219
Total	5,022	8,479	11,568	14,453	19,850	24,931
Fuel Costs	1,906	3,812	5,718	7,624	11,436	15,248
Steam Cost: Total	14,673	24,614	33,456	41,685	57,014	71,376
$/m3	10.05	8.43	7.64	7.14	6.51	6.11

Because the proximity of supply, coke suffers only slightly from de-sulphurization costs. The coke-natural gas cross-over occurs at 1,733 m^3/d (10,900 BOPD) at a steam cost of $8.30/$m^3$. The cost of coke-raised steam drops to $6.11/$m^3$ at 6,400 m^3/d of crude production.

As with the other locations, the comparison of steam costs using alternative fuels is illustrated in Figure 8.29. The capital, operating, and fuel cost components of steam costs are illustrated in Figures 8.30 to 8.32.

Figure 8.29

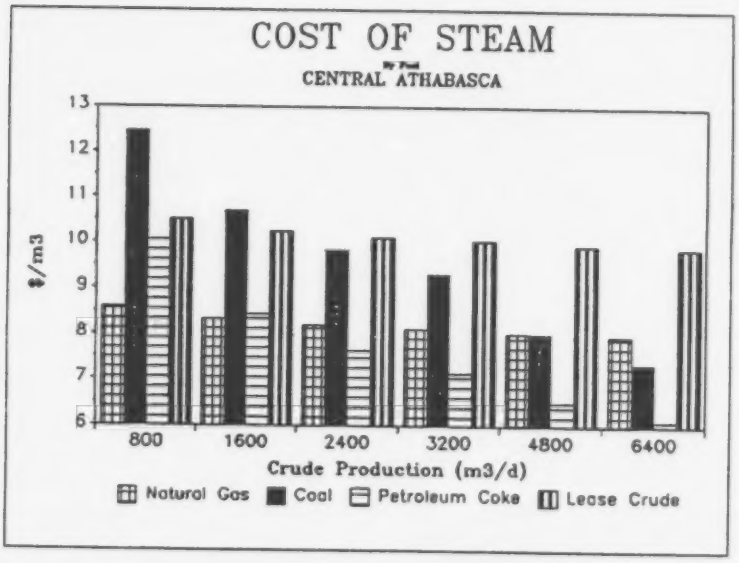


Figure 8.30

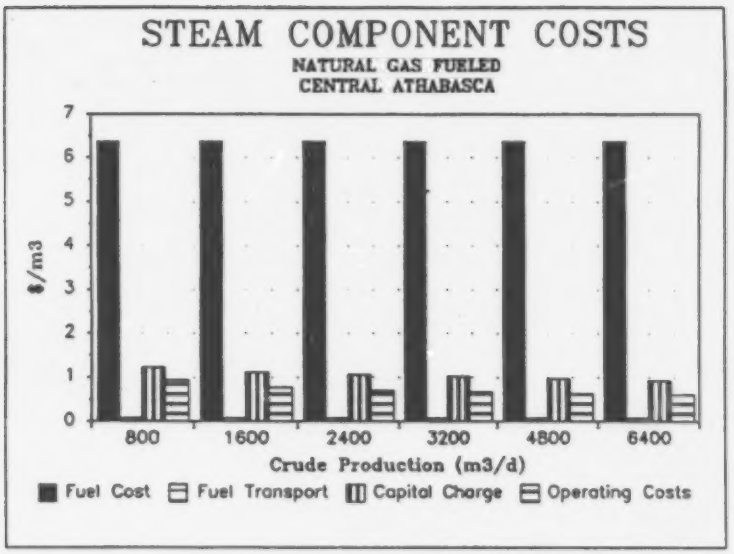


Figure 8.31

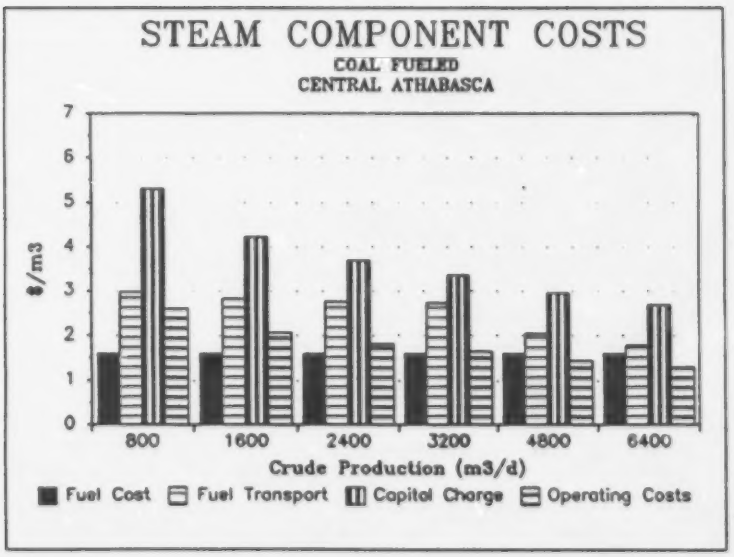
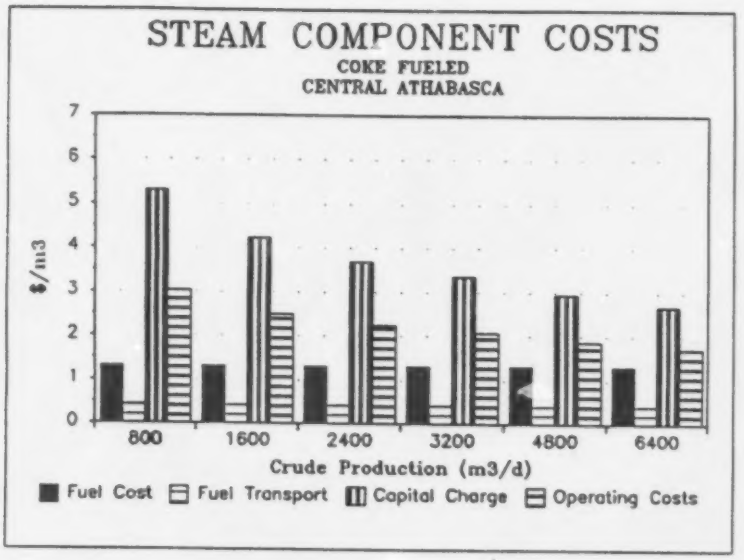


Figure 8.32



8.5.4 Differential Economics

As might be anticipated, coke shows better DCF economics earlier (i.e. lower crude production levels) than coal. In fact, coke begins to challenge natural gas economics at 800 m^3/d (5,000 BOPD). Coal begins to be competitive with natural gas at 3,200 m^3/d (20,000 BOPD). These results are presented and illustrated in Tables 8.22 and 8.23 and Figures 8.33 and 8.34.

Table 8.22

DIFFERENTIAL ECONOMICS*
COAL - NATURAL GAS
($ 000)

C.Athabasca

OIL PRODUCTION(m3/d)	800	1,600	2,400	3,200	4,800	6,400
ALTERNATE FUEL:						
Source	Morinvll	Morinvll	Morinvll	Morinvll	Morinvll	Morinvll
Transport Mode	Truck	Truck	Truck	Truck	Pipeline	Pipeline
Combustion Mode	fbc530	fbc530	fbc530	fbc530	fbc530	fbc530
CAPITAL DIFFERENCE						
Transportation**	943	446	-51	-549	-2,983	-3,977
Site Facilities	28,392	43,272	55,160	65,398	82,872	97,788
Total	29,335	43,718	55,108	64,849	79,889	93,811
OPERATING DIFFERENCE						
Transportation	4,030	7,903	11,738	15,572	17,931	20,860
Site Facilities	2,427	3,781	4,840	5,713	7,127	8,278
Fuel Cost	-6,972	-13,944	-20,916	-27,888	-41,832	-55,776
Total	-514	-2,260	-4,338	-6,603	-16,774	-26,638
ECONOMIC PARAMETERS						
Payback(years)	57.04	19.35	12.70	9.82	4.76	3.52
IRR(%) ***	-8.4%	0.3%	4.8%	8.0%	20.5%	28.2%
NPV at 9%	-24,640	-23,091	-15,511	-4,571	73,230	149,358
12%	-25,493	-26,840	-22,708	-15,527	45,401	105,162
15%	-26,116	-29,574	-27,957	-23,517	25,103	72,927

* Includes de-sulphurization.
** Pipelines are assumed to be owned by outside investors.
*** Discount rates do not include the inflation rate.

Table 8.23

DIFFERENTIAL ECONOMICS*
COKE - NATURAL GAS
($ 000)

C.Athabasca

OIL PRODUCTION(m3/d)	800	1,600	2,400	3,200	4,800	6,400
ALTERNATE FUEL:						
Source	Tar Isl.	Tar Isl.	Tar Isl.	Tar Isl.	Tar Isl.	Tar Isl.
Transport Mode	Truck	Truck	Truck	Truck	Truck	Truck
Combustion Mode	fbc530	fbc530	fbc530	fbc530	fbc530	fbc530
CAPITAL DIFFERENCE						
Transportation**	-497	-994	-1,491	-1,989	-2,983	-3,977
Site Facilities	28,392	43,272	55,160	65,398	82,872	97,788
Total	27,895	42,278	53,668	63,409	79,889	93,811
OPERATING DIFFERENCE						
Transportation	614	1,210	1,795	2,376	3,533	4,691
Site Facilities	3,051	5,027	6,709	8,206	10,866	13,263
Fuel Cost	-7,395	-14,790	-22,185	-29,580	-44,370	-59,160
Total	-3,730	-8,553	-13,681	-18,999	-29,971	-41,206
ECONOMIC PARAMETERS						
Payback(years)	7.48	4.94	3.92	3.34	2.67	2.28
IRR(%) ***	12.0%	19.7%	25.2%	29.8%	37.5%	43.9%
NPV at 9%	6,158	35,800	71,216	110,021	193,704	282,339
12%	-31	21,610	48,519	78,500	143,979	213,974
15%	-4,545	11,259	31,963	55,510	107,710	164,110

* Includes de-sulphurization.
** Pipelines are assumed to be owned by outside investors.
*** Discount rates do not include the inflation rate.

Figure 8.33

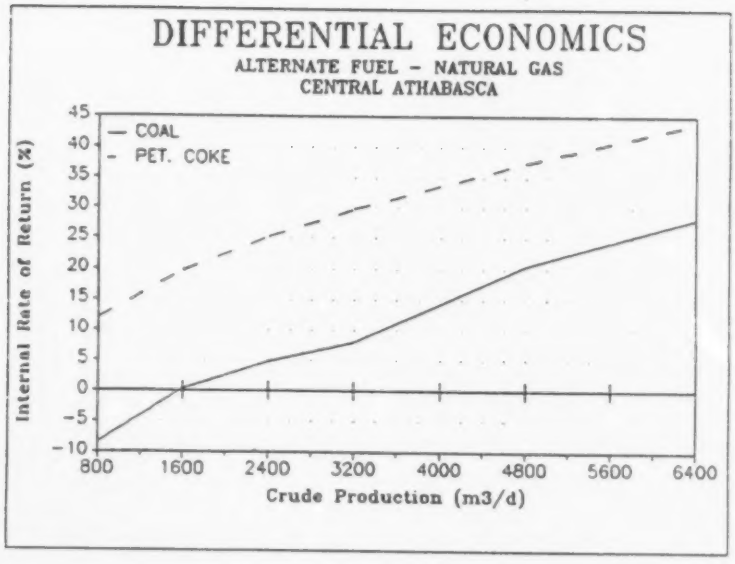
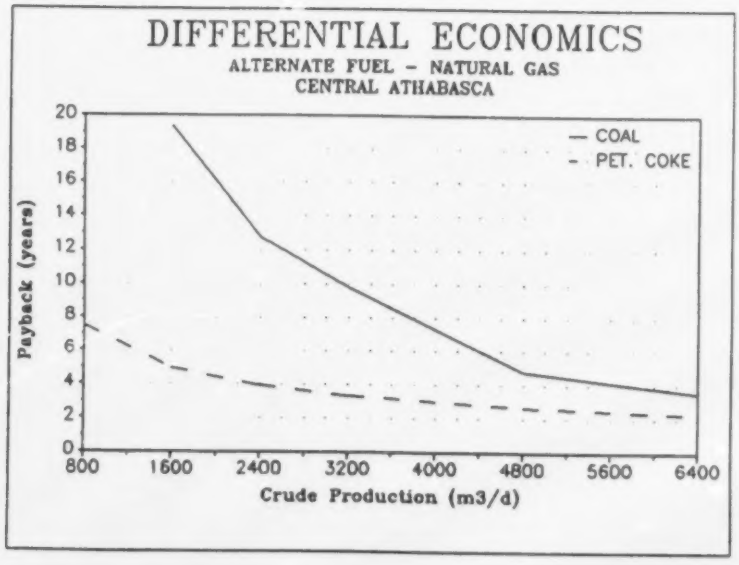


Figure 8.34



8.5.5 Gas Equivalent Capital Costs

On the utility costing (i.e. accounting) or "book" basis, equivalency with gas, on the cost of generated steam, occurs at 4,301 m^3/d (30,200 BOPD) for coal and 1,695 m^3/d (10,660 BOPD) for coke at Central Athabasca. The cross-over for coke occurs at a lower crude production level even though coke incurs higher capital and operating costs (ex fuel and transportation). These results are presented in Table 8.24 and Figures 8.35 and 8.36.

Table 8.24

GAS EQUIVALENT CAPITAL COSTS*
($ 000)

C.Athabasca

OIL PRODUCTION(m3/d)	800	1,600	2,400	3,200	4,800	6,400
COAL:						
Source	Morinvll	Morinvll	Morinvll	Morinvll	Morinvll	Morinvll
Transport Mode	Truck	Truck	Truck	Truck	Pipeline	Pipeline
Combustion Mode	fbc530	fbc530	fbc530	fbc530	fbc530	fbc530
Steam Generators	0.94	1.88	2.81	3.75	5.63	7.50
Capital Cost:						
Equivalent	18,818	36,539	53,852	70,924	122,504	170,755
Estimated	36,883	58,683	77,001	93,369	122,514	148,557
Difference	-18,065	-22,144	-23,149	-22,445	-10	22,198
Unit Cost:						
Equivalent	20,063	19,478	19,138	18,904	21,768	22,756
Estimated	39,322	31,282	27,365	24,886	21,770	19,798
Difference	-19,260	-11,805	-8,227	-5,982	-2	2,958
COKE:						
Source	Tar Isl.	Tar Isl.	Tar Isl.	Tar Isl.	Tar Isl.	Tar Isl.
Transport Mode	Truck	Truck	Truck	Truck	Truck	Truck
Combustion Mode	fbc530	fbc530	fbc530	fbc530	fbc530	fbc530
Steam Generators	0.94	1.88	2.81	3.75	5.63	7.50
Capital Cost:						
Equivalent	30,075	57,643	84,712	111,551	164,730	217,365
Estimated	36,883	58,683	77,001	93,369	122,514	148,557
Difference	-6,807	-1,040	7,712	18,182	42,216	68,808
Unit Cost:						
Equivalent	32,065	30,728	30,105	29,733	29,271	28,968
Estimated	39,322	31,282	27,365	24,886	21,770	19,798
Difference	-7,258	-555	2,741	4,846	7,501	9,170

* De-sulphurization capital excluded.

Figure 8.35

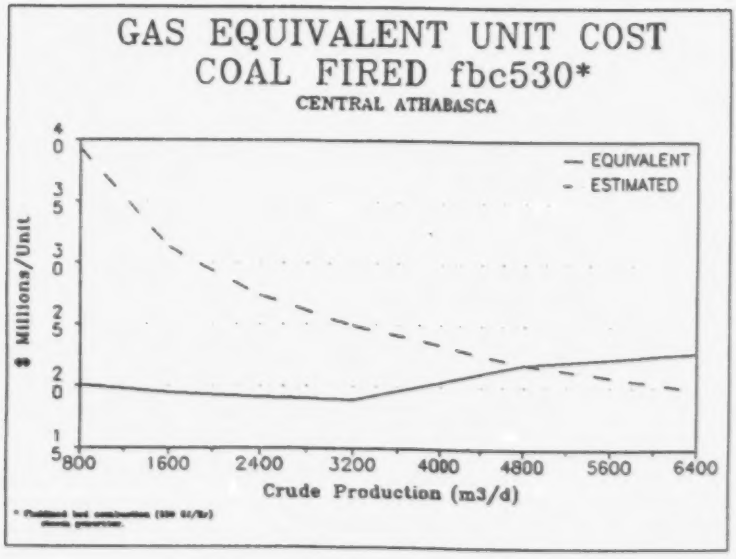
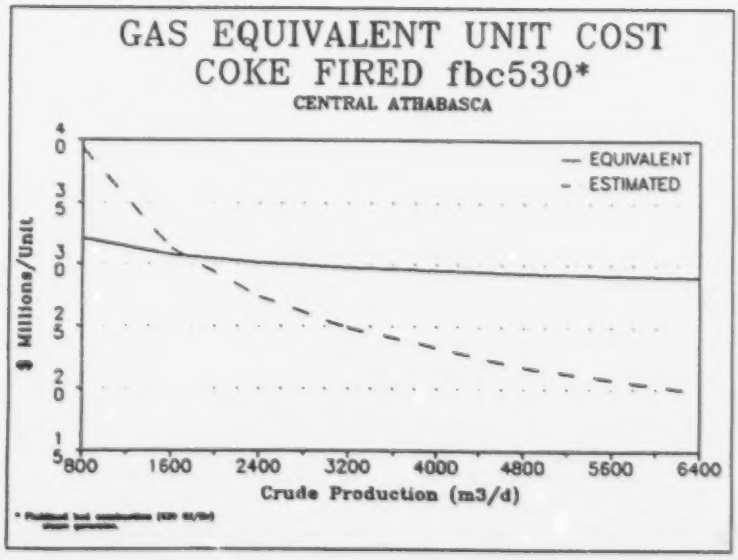


Figure 8.36

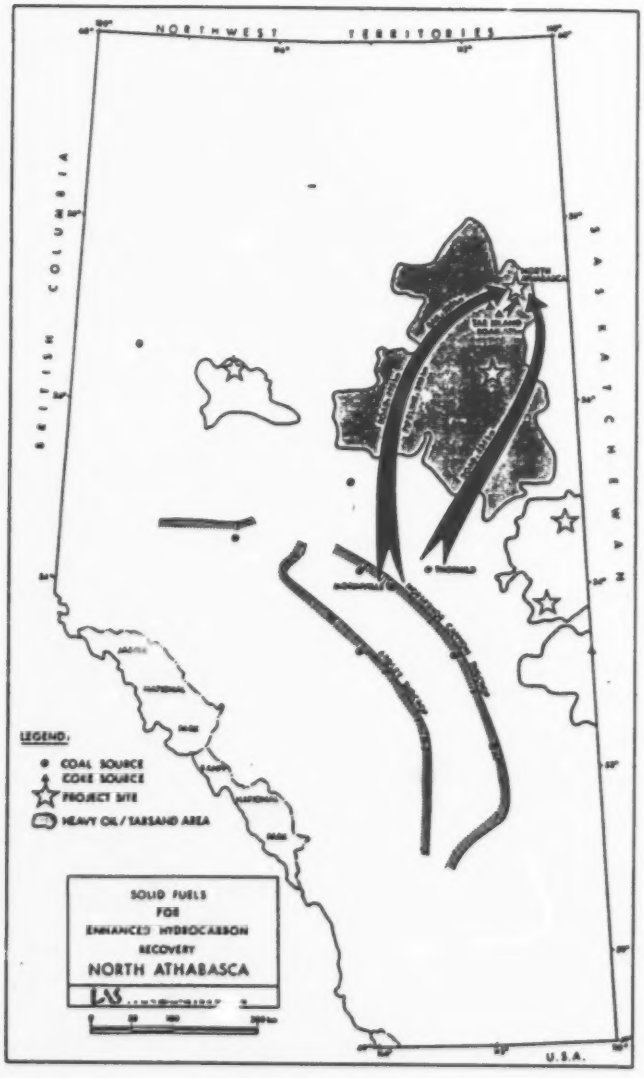


8.6 Northern Athabasca

The location and logistics of the Northern Athabasca producing area and selected site are illustrated in Figure 8.37.

Figure 8.37

North Athabasca - Project Location



8.6.1 Site Facilities

Because the same steam/oil ratio was assumed for Northern Athabasca and Central Athabasa, the facilities requirements are exactly the same at each production level as shown on Table 8.25.

Table 8.25

STEAM CAPITAL & OPERATING COSTS

N.Athabasca

STEAM GENERATION PARAMETERS						
Steam/Oil Ratio(m3/m3)		5.00				
Steam Heat Content(GJ/m3)		2.15				
PRODUCTION						
Oil(m3/day)	800	1,600	2,400	3,200	4,800	6,400
Steam(K m3/year)	1,460	2,920	4,380	5,840	8,760	11,680
FUEL CONSUMED(TJ/y)	3,702	7,403	11,105	14,806	22,209	29,612
STEAM GENERATORS:						
gas190 Units	2.47	4.94	7.41	9.88	14.83	19.77
Capital Cost($ K)	8,491	15,411	21,841	27,971	39,642	50,769
Annualized($ K):						
Capital	1,783	3,236	4,587	5,874	8,325	10,662
Operating	1,355	2,237	3,056	3,862	5,436	6,956
Total	3,138	5,473	7,643	9,736	13,761	17,618
pcf530 Units	0.94	1.88	2.81	3.75	5.63	7.50
Capital Cost($ K)	40,427	64,323	84,401	102,342	134,288	162,834
Annualized($ K):						
Capital	8,490	13,508	17,724	21,492	28,200	34,195
Operating	3,236	5,149	6,756	8,192	10,749	13,034
Total	11,726	18,657	24,480	29,684	38,950	47,229
fbc370 Units	1.34	2.69	4.03	5.37	8.06	10.75
Capital Cost($ K)	40,220	63,993	83,969	101,818	133,600	162,000
Annualized($ K):						
Capital	8,446	13,439	17,633	21,382	28,056	34,020
Operating	4,124	6,562	8,611	10,441	13,700	16,612
Total	12,571	20,001	26,244	31,823	41,756	50,632
fbc530 Units	0.94	1.88	2.81	3.75	5.63	7.50
Capital Cost($ K)	36,883	58,683	77,001	93,369	122,514	148,557
Annualized($ K):						
Capital	7,745	12,323	16,170	19,608	25,728	31,197
Operating	3,782	6,018	7,896	9,575	12,563	15,234
Total	11,528	18,341	24,066	29,182	38,291	46,431

NOTE: Excludes fuel and de-sulphurization.

8.6.2 Delivered Fuel Costs

The delivered fuel costs to Northern Athabasca are different from those of Central Athabasca by the changed transportation costs. Coal costs increase

proportionately more than coke costs drop, on the change in site, because of the construction of new coal transportation facilities. The delivered coke cost increases are nominal, as shown in Table 8.26 compared with Table 8.20.

Table 8.26

FUEL COST COMPARISON

N.Athabasca

PRODUCTION						
Oil(m3/day)	800	1,600	2,400	3,200	4,800	6,400
Steam(K m3/year)	1,460	2,920	4,380	5,840	8,760	11,680
FUEL CONSUMED(TJ/y)	3,702	7,403	11,105	14,806	22,209	29,612
NATURAL GAS:						
Combustion Mode	gas190	gas190	gas190	gas190	gas190	gas190
Consumed(MM m3/y)	99.4	198.9	298.3	397.7	596.6	795.4
Price($/K m3)	93.54	93.54	93.54	93.54	93.54	93.54
Unit Steam Costs:						
$/GJ (gas)	3.39	3.28	3.23	3.20	3.16	3.14
$/K m3 (gas)	126.18	122.14	120.24	119.10	117.69	116.77
$/m3 (steam)	8.59	8.32	8.19	8.11	8.01	7.95
COAL:						
Source	Morinvll	Morinvll	Morinvll	Morinvll	Morinvll	Morinvll
Transport Mode	Truck	Truck	Unitrain	Unitrain	Unitrain	Unitrain
Combustion Mode	fbc530	fbc530	fbc530	fbc530	fbc530	fbc530
HeatContent(GJ/T)	18.60	18.60	18.60	18.60	18.60	18.60
Consumed(K T/y)	199.0	398.0	597.0	796.0	1,194.0	1,592.1
Price($/T):						
F.O.B. Source	11.70	11.70	11.70	11.70	11.70	11.70
Delivered	40.83	39.55	38.22	34.49	30.74	29.03
Unit Steam Costs:						
$/GJ (coal)	5.31	4.60	4.22	3.83	3.38	3.13
$/Tonne (coal)	98.76	85.63	78.53	71.15	62.80	58.19
$/m3 (steam)	13.46	11.67	10.70	9.70	8.56	7.93
COKE:						
Source	Tar Isl.	Tar Isl.	Tar Isl.	Tar Isl.	Tar Isl.	Tar Isl.
Transport Mode	Truck	Truck	Truck	Truck	Truck	Truck
Combustion Mode	fbc530	fbc530	fbc530	fbc530	fbc530	fbc530
HeatContent(GJ/T)	33.50	33.50	33.50	33.50	33.50	33.50
Consumed(K T/y)	110.5	221.0	331.5	442.0	663.0	883.9
Price($/T):						
F.O.B. Source	17.25	17.25	17.25	17.25	17.25	17.25
Delivered	22.21	22.14	22.08	22.05	22.01	21.99
Unit Steam Costs:						
$/GJ (coke)	3.95	3.31	2.99	2.80	2.55	2.39
$/Tonne (coke)	132.18	110.77	100.33	93.72	85.40	80.15
$/m3 (steam)	10.00	8.38	7.59	7.09	6.46	6.07

NOTE: Includes de-sulphurization.

8.6.3 Cost of Steam

The affects of the additional transportation costs to Northern Athabasca moves the coal-natural gas cross-over to 6,344 m3/d (39,900 BOPD) for coal at a steam cost of $7.95/m3. Similarly, the coke-natural gas cross over of $8.30/m3 corresponding to the reduction in transportation costs. Therefore, coke-raised steam is less costly than coal-raised steam at all levels of crude production examined for Northern Athabasca as shown in Table 8.27.

Table 8.27

ANNUAL COST OF STEAM
($ 000)

N.Athabasca

PRODUCTION						
Oil(m3/day)	800	1,600	2,400	3,200	4,800	6,400
Steam(K m3/year)	1,460	2,920	4,380	5,840	8,760	11,680
NATURAL GAS						
Capital Charges:						
Transportation	104	209	313	418	626	835
Site Facilities	1,783	3,236	4,387	5,874	8,325	10,662
Total	1,887	3,445	4,700	6,292	8,951	11,497
Operating Costs:						
Transportation	2	5	7	10	15	20
Site Facilities	1,355	2,237	3,056	3,862	5,436	6,956
Total	1,357	2,242	3,064	3,872	5,451	6,976
Fuel Costs	9,301	18,602	27,903	37,204	55,806	74,408
Steam Cost: Total	12,546	24,289	35,867	47,367	70,209	92,881
$/m3	8.59	8.32	8.19	8.11	8.01	7.95
COAL						
Source	Morinvll	Morinvll	Morinvll	Morinvll	Morinvll	Morinvll
Transport Mode	Truck	Truck	Unitrain	Unitrain	Unitrain	Unitrain
Combustion Mode	fbc530	fbc530	fbc530	fbc530	fbc530	fbc530
Capital Charges:						
Transportation	302	302	5,040	5,040	5,040	5,040
Site Facilities	7,745	12,323	16,170	19,608	25,728	31,197
Total	8,048	12,626	21,210	24,648	30,768	36,237
Operating Costs:						
Transportation	5,495	10,781	10,792	13,099	17,686	22,543
Site Facilities	3,782	6,018	7,896	9,575	12,563	15,234
Total	9,277	16,798	18,688	22,673	30,249	37,777
Fuel Costs	2,329	4,658	6,987	9,316	13,974	18,633
Steam Cost: Total	19,654	34,082	46,885	56,637	74,991	92,647
$/m3	13.46	11.67	10.70	9.70	8.56	7.93
COKE						
Source	Tar Isl.	Tar Isl.	Tar Isl.	Tar Isl.	Tar Isl.	Tar Isl.
Transport Mode	Truck	Truck	Truck	Truck	Truck	Truck
Combustion Mode	fbc530	fbc530	fbc530	fbc530	fbc530	fbc530
Capital Charges:						
Transportation	0	0	0	0	0	0
Site Facilities	7,745	12,323	16,170	19,608	25,728	31,197
Total	7,745	12,323	16,170	19,608	25,728	31,197
Operating Costs:						
Transportation	548	1,080	1,602	2,121	3,154	4,188
Site Facilities	4,405	7,264	9,766	12,067	16,302	20,219
Total	4,953	8,344	11,368	14,188	19,456	24,407
Fuel Costs	1,906	3,812	5,718	7,624	11,436	15,248
Steam Cost: Total	14,605	24,479	33,256	41,420	56,620	70,852
$/m3	10.00	8.38	7.59	7.09	6.46	6.07

Figures 8.38 to 8.41 emphasize the dominant effect of fuel transportation costs upon the steam costs by generating fuel alternatives.

Figure 8.38

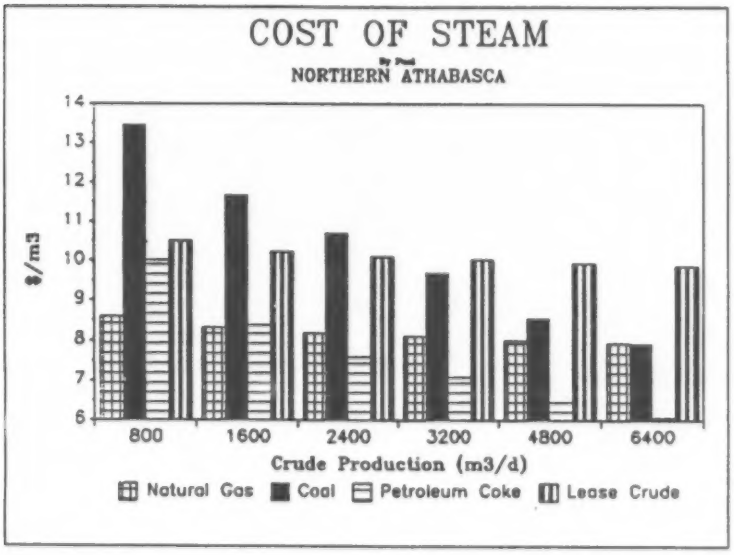


Figure 8.39

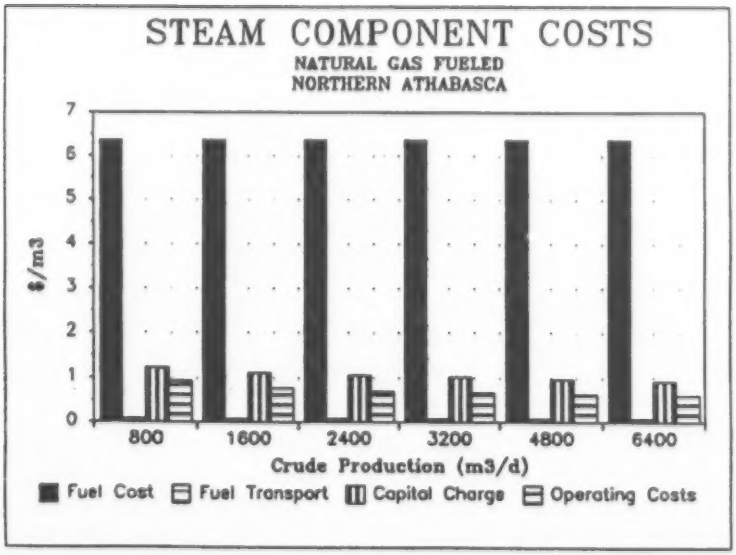


Figure 8.40

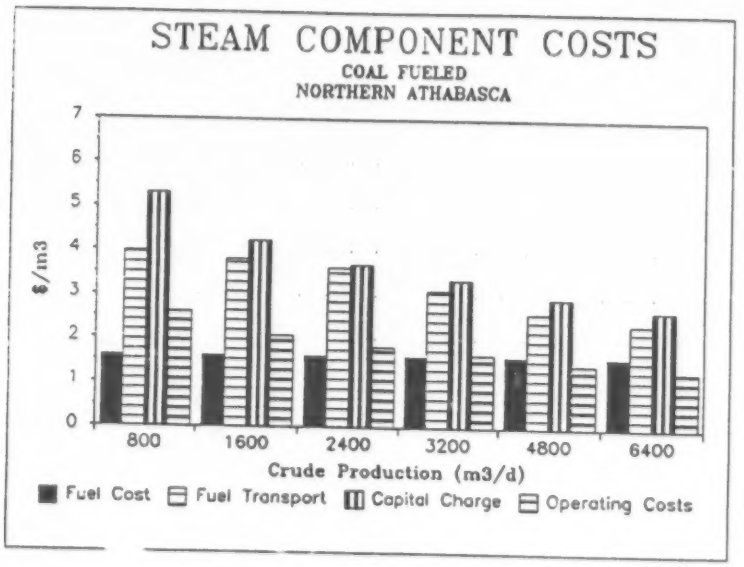
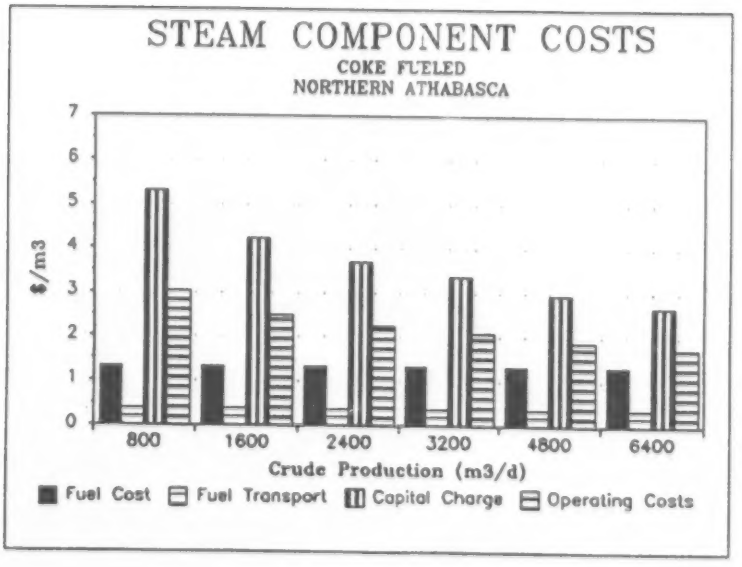


Figure 8.41



8.6.4 Differential Economics

The transportation advantages of coke over coal shows clearly, at Northern Athabasca, in Tables 8.28 and 8.29 and Figures 8.42 and 8.43. Coal never catches up

Table 8.28

DIFFERENTIAL ECONOMICS*
COAL - NATURAL GAS
($ 000)

	N.Athabasca					
OIL PRODUCTION(m3/d)	800	1,600	2,400	3,200	4,800	6,400
ALTERNATE FUEL:						
Source	Morinvll	Morinvll	Morinvll	Morinvll	Morinvll	Morinvll
Transport Mode	Truck	Truck	Unitrain	Unitrain	Unitrain	Unitrain
Combustion Mode	fbc530	fbc530	fbc530	fbc530	fbc530	fbc530
CAPITAL DIFFERENCE						
Transportation**	943	446	22,509	22,011	21,017	20,023
Site Facilities	28,392	43,272	55,160	65,398	82,872	97,788
Total	29,335	43,718	77,668	87,409	103,889	117,811
OPERATING DIFFERENCE						
Transportation	5,492	10,776	10,784	13,089	17,671	22,523
Site Facilities	2,427	3,781	4,840	5,713	7,127	8,278
Fuel Cost	-6,972	-13,944	-20,916	-27,868	-41,832	-55,776
Total	948	613	-5,292	-9,086	-17,034	-24,975
ECONOMIC PARAMETERS						
Payback(years)	-30.95	-71.36	14.68	9.62	6.10	4.72
IRR(%) ***	0.0%	0.0%	3.1%	8.3%	15.5%	20.7%
NPV at 9%	-37,986	-49,310	-29,360	-4,464	51,607	110,175
12%	-36,414	-48,294	-38,140	-19,539	23,346	68,739
15%	-35,267	-47,552	-44,544	-30,535	2,733	38,516

* Includes de-sulphurization.
** Pipelines are assumed to be owned by outside investors.
*** Discount rates do not include the inflation rate.

Table 8.29

DIFFERENTIAL ECONOMICS*
COKE - NATURAL GAS
($ 000)

	N.Athabasca					
OIL PRODUCTION(m3/d)	800	1,600	2,400	3,200	4,800	6,400
ALTERNATE FUEL:						
Source	Tar Isl.	Tar Isl.	Tar Isl.	Tar Isl.	Tar Isl.	Tar Isl.
Transport Mode	Truck	Truck	Truck	Truck	Truck	Truck
Combustion Mode	fbc530	fbc530	fbc530	fbc530	fbc530	fbc530
CAPITAL DIFFERENCE						
Transportation**	-497	-994	-1,491	-1,989	-2,983	-3,977
Site Facilities	28,392	43,272	55,160	65,398	82,872	97,788
Total	27,895	42,278	53,668	63,409	79,889	93,811
OPERATING DIFFERENCE						
Transportation	546	1,075	1,595	2,111	3,139	4,168
Site Facilities	3,051	5,027	6,709	8,206	10,866	13,263
Fuel Cost	-7,395	-14,790	-22,185	-29,580	-44,370	-59,160
Total	-3,799	-8,688	-13,881	-19,264	-30,365	-41,729
ECONOMIC PARAMETERS						
Payback(years)	7.34	4.87	3.87	3.29	2.63	2.25
IRR(%) ***	12.3%	20.0%	25.6%	30.2%	37.9%	44.5%
NPV at 9%	6,783	37,032	73,044	112,441	197,303	287,117
12%	480	22,618	50,015	80,480	146,924	217,884
15%	-4,117	12,104	33,217	57,169	110,178	167,387

* Includes de-sulphurization.
** Pipelines are assumed to be owned by outside investors.
*** Discount rates do not include the inflation rate.

to coke at Northern Athabasca. Coke is competitive, on a DCF basis, with natural gas even at 1,600 m^3/d (10,000 BOPD) of production.

Figure 8.42

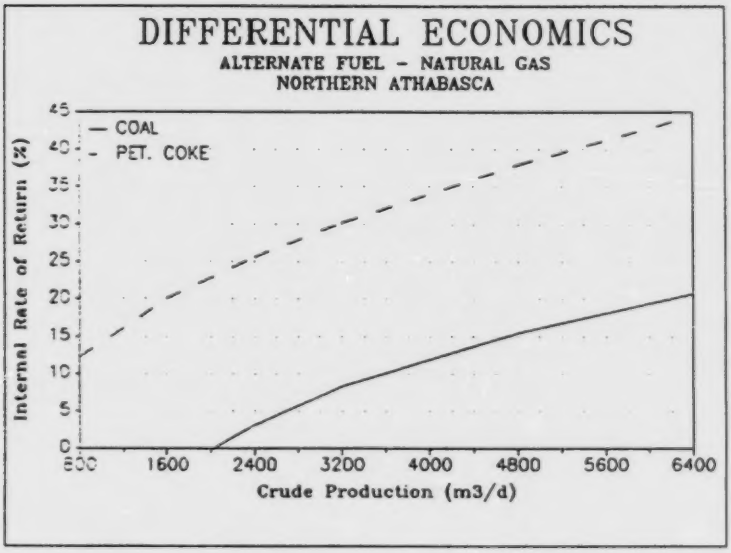
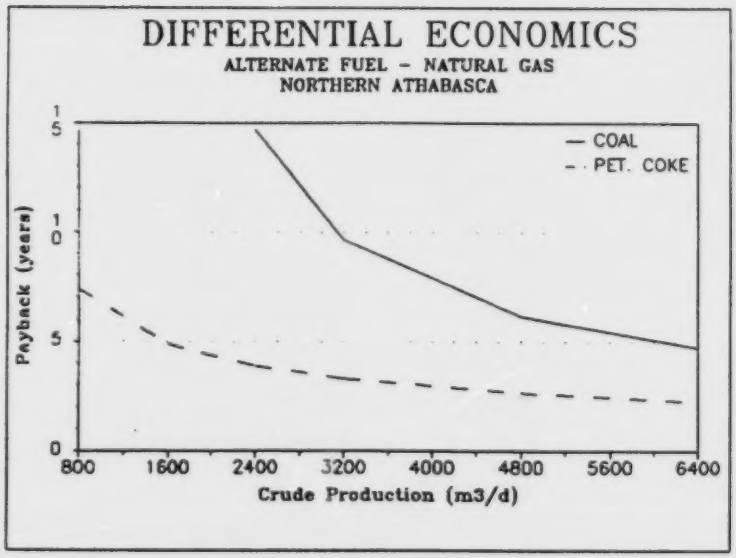


Figure 8.43



8.6.5 Gas Equivalent Capital Costs

Capital equivalency with gas, on the utility cost of generated steam, occurs at 6,343 m^3/d (39,900 BOPD) for coal but at 1,679 m^3/d (10,560 BOPD) for coke at Northern Athabaasca. These results are presented in Table 8.30 and Figure 8.44 and 8.45.

Table 8.30

North Athabasca - Gas Equivalent Capital Cost

GAS EQUIVALENT CAPITAL COSTS*
($ 000)

N.Athabasca

OIL PRODUCTION(m3/d)	800	1,600	2,400	3,200	4,800	6,400
COAL:						
Source	Morinvll	Morinvll	Morinvll	Morinvll	Morinvll	Morinvll
Transport Mode	Truck	Truck	Unitrain	Unitrain	Unitrain	Unitrain
Combustion Mode	fbc530	fbc530	fbc530	fbc530	fbc530	fbc530
Steam Generators	0.94	1.88	2.81	3.75	5.63	7.50
Capital Cost:						
Equivalent	14,140	27,349	41,747	63,711	107,211	149,308
Estimated	36,883	58,683	77,001	93,369	122,514	148,557
Difference	-22,743	-31,334	-35,254	-29,658	-15,302	751
Unit Cost:						
Equivalent	15,076	14,579	14,836	16,981	19,051	19,898
Estimated	39,322	31,282	27,365	24,886	21,770	19,798
Difference	-24,247	-16,703	-12,529	-7,905	-2,719	100
COKE:						
Source	Tar Isl.	Tar Isl.	Tar Isl.	Tar Isl.	Tar Isl.	Tar Isl.
Transport Mode	Truck	Truck	Truck	Truck	Truck	Truck
Combustion Mode	fbc530	fbc530	fbc530	fbc530	fbc530	fbc530
Steam Generators	0.94	1.88	2.81	3.75	5.63	7.50
Capital Cost:						
Equivalent	30,295	58,074	85,353	112,399	165,991	219,040
Estimated	36,883	58,683	77,001	93,369	122,514	148,557
Difference	-6,588	-609	8,353	19,030	43,477	70,483
Unit Cost:						
Equivalent	32,299	30,958	30,333	29,959	29,495	29,191
Estimated	39,322	31,282	27,365	24,886	21,770	19,798
Difference	-7,024	-324	2,968	5,072	7,726	9,393

* De-sulphurization capital excluded.

Figure 8.44

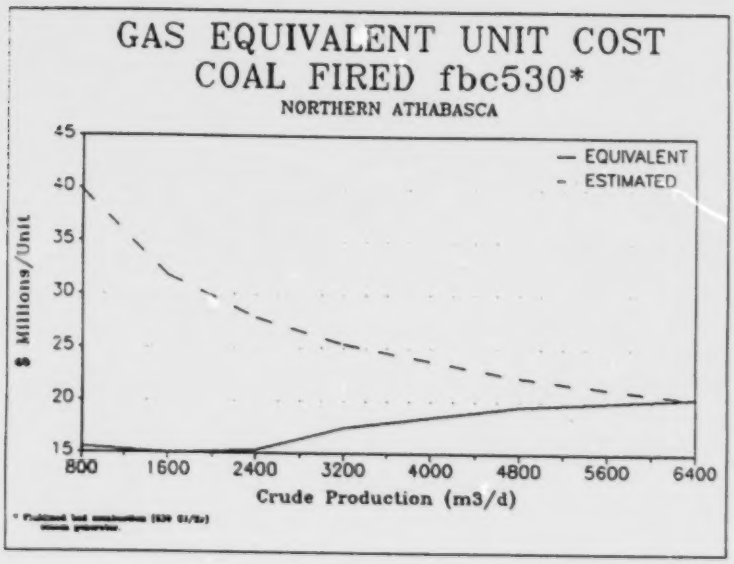
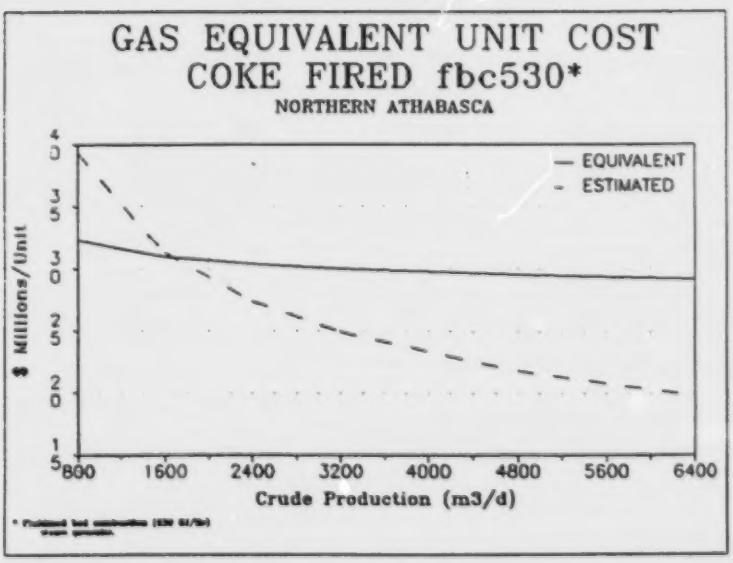


Figure 8.45



8.7 Sensitivity Analyses

"Point" measures of alternate fuels economics are valid indicators of expected economics but do not provide any indication of how sensitive the economics are to changes in the critical project variables. For the purposes of this study, the critical project variables are:

a) natural gas prices,
b) steam generator capital costs for alternate fuels, and
c) steam/oil ratios.

Investigation of the economics sensitivity to each of these parameters for all producing areas would quickly cause indigestion in the most diligent reader of this study. Therefore, the sensitivity analysis of this study is limited to Lindbergh as the reference area. With some exercise of judgement, the results can be transposed to other producing areas.

The capital cost estimates of coal and coke fired steam generating facilities already contain large contingency components for unknown risks. Beyond the experimental phase and into the commercial production phase, it is more probable that the capital costs of coal and coke fired steam generators would be reduced from the base case estimates, rather than increased.

8.7.1 Equivalent Steam Cost Production Levels

The crude production level at which the cost of steam is equal for natural gas and the alternate fuel is dependent upon each of the project variables listed above. Above this production level the alternate fuel generates steam of lower cost than natural gas and vice versa. Figures 8.46 and 8.47 show the sensitivity of the equivalence or "cross-over" production level to changes in the critical project variables for both coal and coke at Lindbergh. The sensitivity of cross-over points to capital cost and natural gas price is about the same (higher for gas price) and almost triple the sensitivity to steam/oil ratio. Coke cross-over points are as sensitive as coal cross-over points to changes in the project variable. The slopes of the curves in

Figures 8.46 and 8.47 are measures of the sensitivities at points along the horizontal axis. The average slopes at a small interval about the base case variable values are listed on Table 8.31. The order of sensitivity is natural gas price > capital cost > steam/oil ratio.

Table 8.31
Economic Parameter Curve Slopes
Lindbergh

Project Variable	Cross-Over Point (m^3/d/10% change)*		DCF IRR (%/10% change)*	
	Coal	Coke	Coal	Coke
Natural Gas Price	-1040	-1200	4.8%	5.5%
Capital Cost	840	930	-3.85%	-5.1%
Steam/Oil Ratio	- 380	- 300	1.8%	1.4%

* **Note:** Change in economic parameter per 10% change (-5% to + 5%) in variable value from base case value.

8.7.2 Differential Economics

As discussed in the economics section for each producing area examined in this study, the differential DCF parameters are strong functions of crude production level. In Figures 8.48 and 8.49, the sensitivity of the internal rate of return the critical project parameters is illustrated for coal and coke. Again the same order of sensitivity is observed: gas price > capital cost > steam oil ratio. A 20% reduction in coal fired steam generators makes coal competitive with natural gas even at 1,600 m^3/d. Also, coal could still compete with natural gas at Lindbergh (10% IRR) if the natural gas price were only $2.00/GJ at a production level of 4,000 m^3/d (25,000 bbl/d). Both Figures 8.48 and 8.49 assume a fixed level of production of 3,200 m^3/d (20,000 BOPD).

The results for coke are shown in Figure 8.49. As discussed before, the economics of coke at Lindbergh are better than coal but the financial risks (indicated by the sensitivities) are similar. Apart from the shift upward from coal to coke, the line slopes and curvatures are very similar for coal and coke at Lindbergh.

Figure 8.46

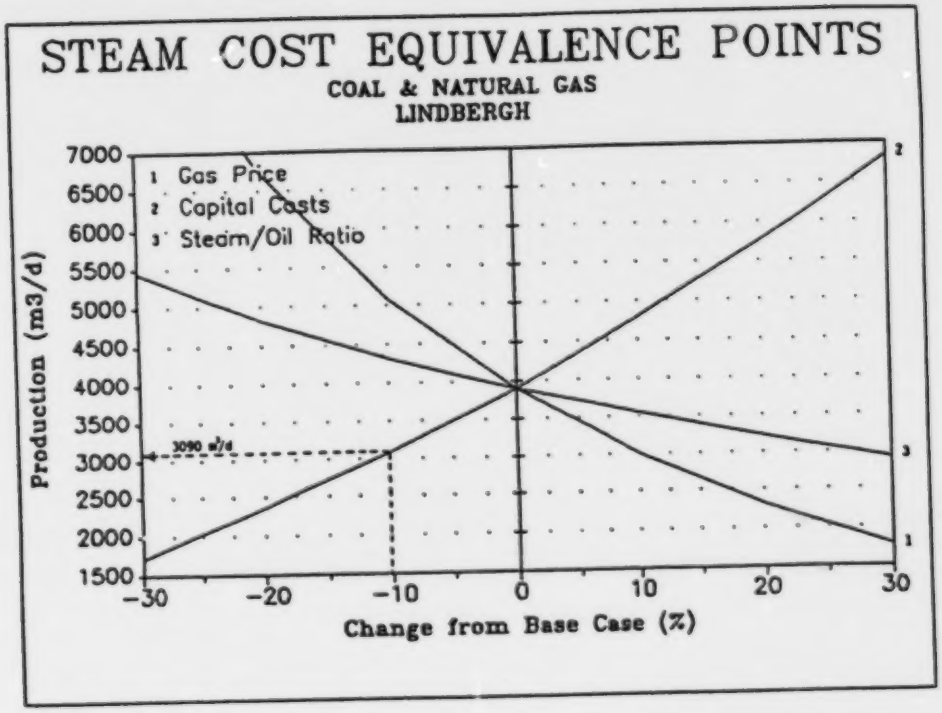


Figure 8.47

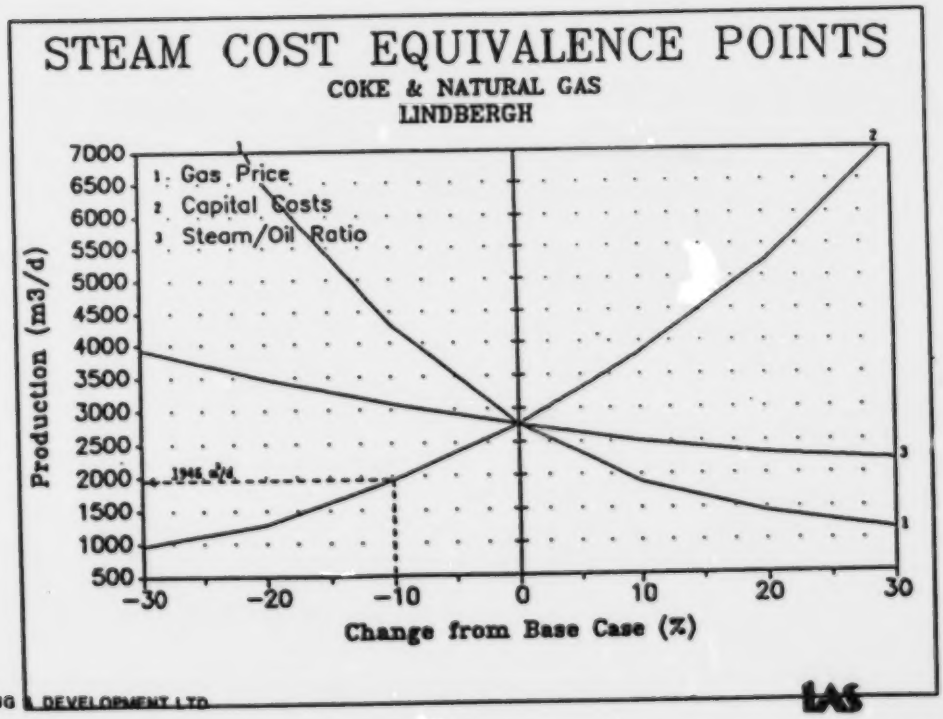


Figure 8.48

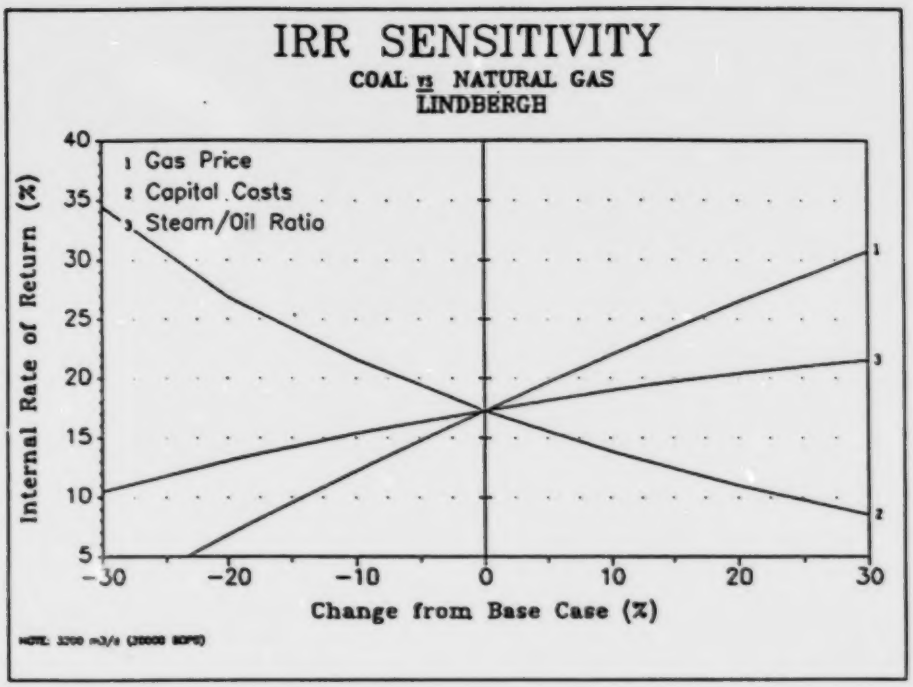
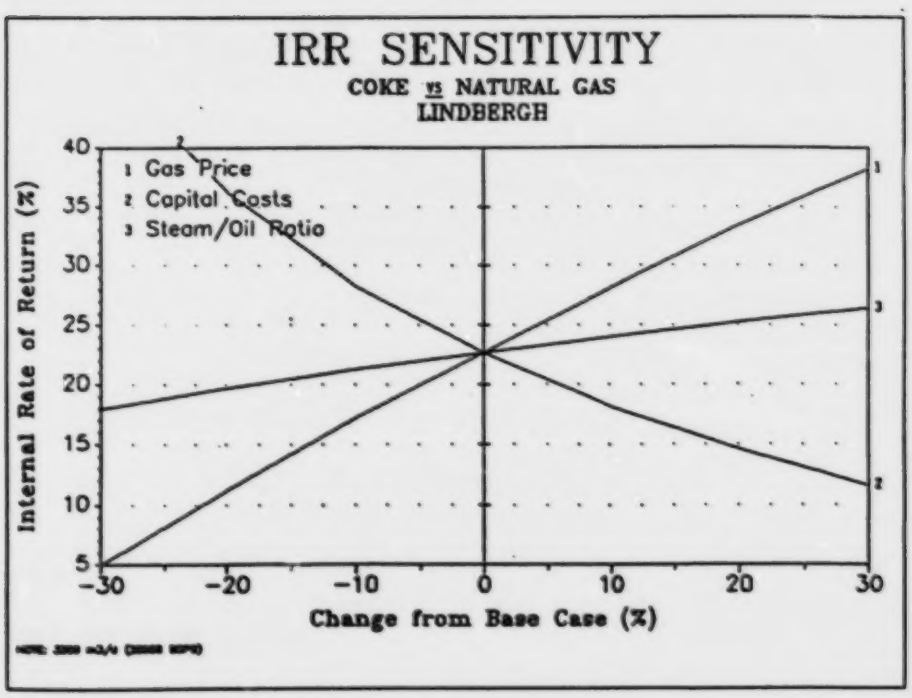


Figure 8.49



Figures 8.53 and 8.54 illustrate on a single graph the sensitivity of the IRR parameter to changes in project variable values from the base case values for each of coal and coke. Symmetrical spacing of the 20% lines about the base case line suggest equal impact of positive or negative variable changes.

Figure 8.50

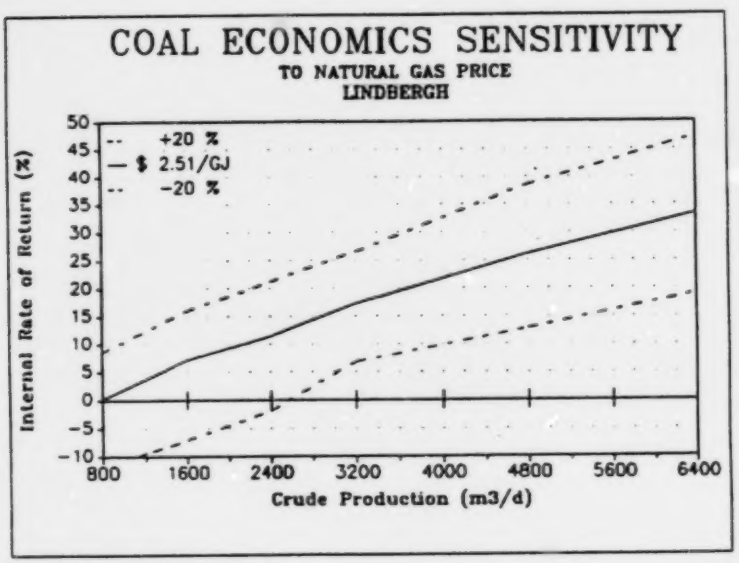
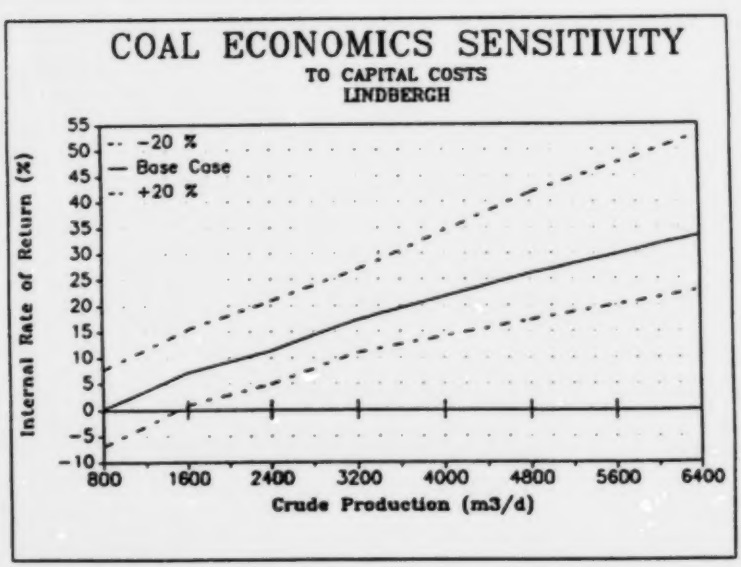


Figure 8.51



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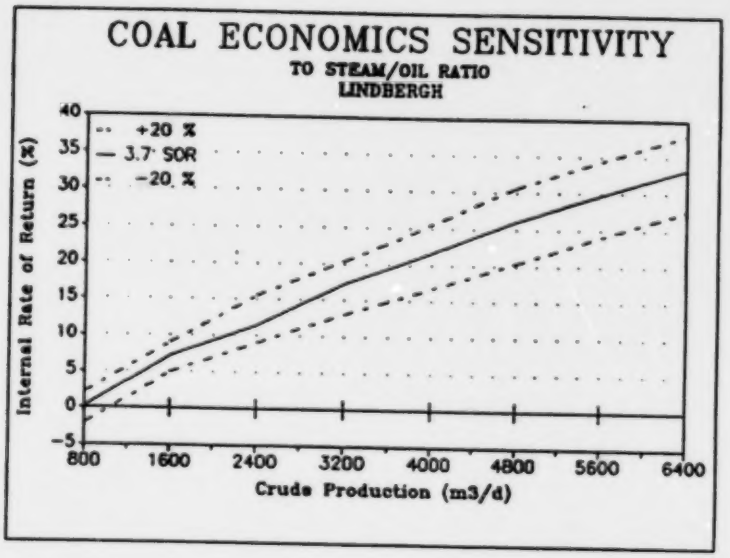
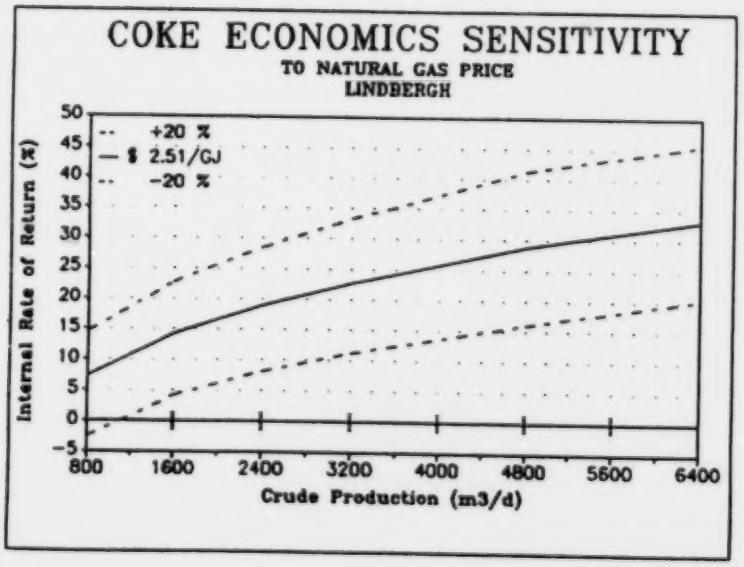


Figure 8.53



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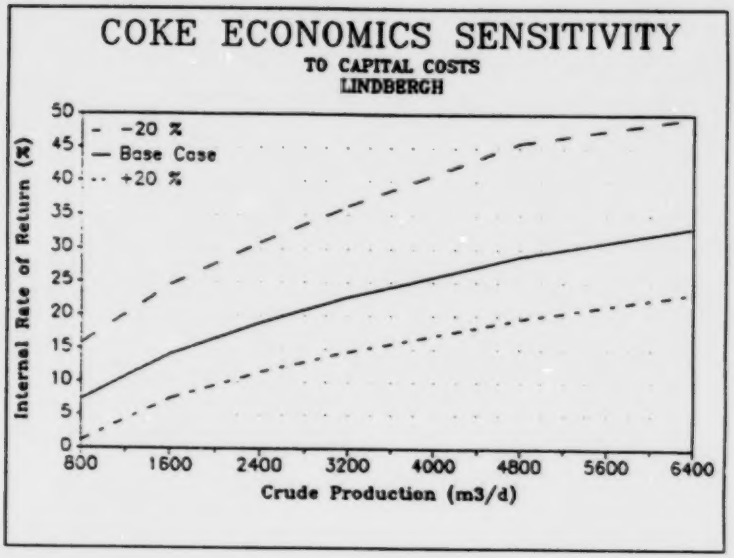
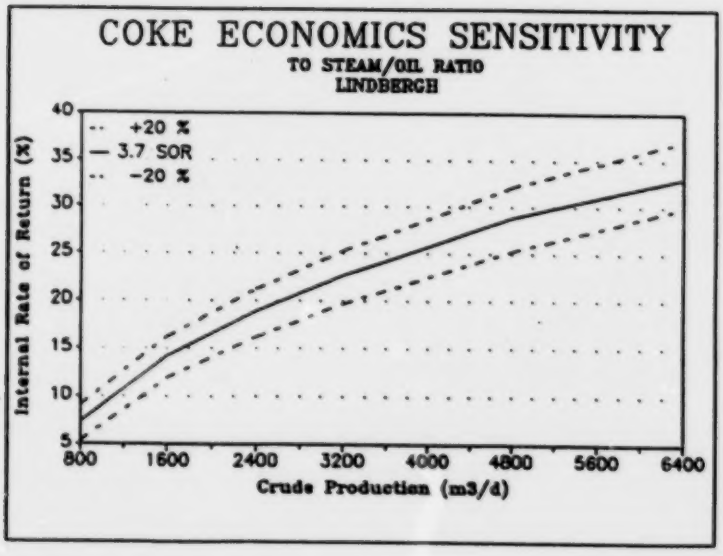


Figure 8.55



9.0 BIBLIOGRAPHY

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9.2 COMBUSTION AND STEAM TECHNOLOGY

9.3 FUELS

9.3.1 Natural Gas

9.3.2 Coal and Coke

9.4 TRANSPORTATION

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10. APPENDICES

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APPENDIX I
FUELOPTS
PROGRAM USER'S GUIDE

1. INTRODUCTION

FUELOPTS is the name of the project file (i.e. program) used to generate the suite of calculated spreadsheets listed in Table I.1. The program and spreadsheets were developed within The Smart Spreadsheet system of Innovative Software on a COMPAQ/DESKPRO Model II microcomputer. Each subscriber to this report is provided with one copy each of data files, spreadsheet files, program file, and graphics definition file on an IBM/PC compatible floppy diskette. All files may be copied either to backup disks, backup files, or the printer. There are no copyright restrictions or passwords. In the following instructions, some familiarity with the SMART software system is assumed.

The economic model, embodied in FUELOPTS, is based upon the assumptions presented and discussed in Section 7 of the main report. The function of FUELOPTS is to combine the raw data with the assumed relationships to produce the layers of cost economics reports numbered 11 to 19 in Table I.1. Once started, the program is dependent upon user attendance only for parameter specification; subsequent calculation and printing are automatic. Graph generation is a separate procedure made less automatic by the nature of the graphics software (FUELOPTS cannot construct the graph definition files).

2. PROGRAM EXECUTION

2.1 Spreadsheet Generation

The SMART software provides a powerful and convenient system for the erection, modification and deletion of spreadsheets. As a preliminary note of caution, all the spreadsheet relationships specified within FUELOPTS assume fixed row and column positions within the spreadsheets listed in Table I.1. Any movements, insertions or deletions of rows or columns may cause the expected relationships to be destroyed. Cosmetic alterations to text

TABLE I.1

FUELOPTS SPREADSHEETS/FILES

	Spreadsheet	Type*	Title	File References**
1	STEAM	D	Steam parameters	-
2	UNITCOST	D	Unit capital and operating costs	-
3	COALDATA	D	Coal data	-
4	COKEDATA	D	Coke data	-
5	RATEDATA	D	Transportation rate parameters	-
6	OLDROAD	D	Connecting distances - old road	-
7	NEWROAD	D	Connecting distances - new road	-
8	OLDRAIL	D	Connecting distances - old rail	-
9	NEWRAIL	D	Connecting distances - new rail	-
10	PIPELINE	D	Connecting distances - pipeline	-
11	SITECOST	C	Steam capital & operating costs	1,2
12	COALCOST	C	Delivered coal cost	3,5-11
13	COKECOST	C	Delivered coke cost	4,5-11
14	COALBURN	C	Summary coal costs by source	11,12
15	COKEBURN	C	Summary coke costs by source	11,13
16	FUELCOST	C	Fuel cost comparison	11,14,15
17	COMPARE	C	Annual cost of steam	11,16
18	DIFFRNCE	C	Differential economics	2,11,16,17
19	EQUICAP	C	Gas equivalent capital costs	2,11,16,17

* Note: D = data
C = calculated (derived from assumed relationships and data)

** Files providing information to current spreadsheet.

entries or movements within cells are possible without disrupting the program logic. If files are to be changed, it is recommended that they be moved to a different file with a new name before the change is made.

With the above cautions in mind, the user should verify all data within the data files, and make the modifications deemed necessary. When the data is acceptable, the program FUELOPTS may be executed by selecting the EXECUTE command from SMART command list 5 (confidence level 3). After several seconds of initialization and housecleaning, an input screen (Figure I-1) will appear for user selection of program options. The user may move around the input screen at leasure until the contents are satisfactory. No input-screen entries have effect until the F/O function key is depressed. Entry of a blank screen will terminate the program execution.

If the user elects to manually select a fuel source (rather than let FUELOPTS select an optimized source), then input screens for the appropriate choices automatically appear and the program pauses until a selection has been made (Figure I.2 and I.3).

Once started, FUELOPTS will run independently until the end of the current production location calculations. At the end of the run, the master input screen will reappear to enable the selection of another production location, manual fuel source, etc. Automatic printing assumes that the printer has been properly initialized and the SMART software knows the printer identity (see the CONFIGURE and PRINTER-CODES commands of the Main-Menu Command List 3). Execution of FUELOPTS may be interrupted or cancelled by pressing the Ctrl and Z keys simultaneously. If interrupted, execution may be restarted by again selecting the EXECUTE command (Command List 5).

The run speed of FUELOPTS is very slow (about 3-1/2 hours for a full run using 6 crude production levels) even on a COMPAQ/Deskpro. Much of the time is spent swapping information to and from the floppy disks. Considerable time may be saved by limiting candidate fuel sources to the minimum reasonable set.

FUELOPTS looks first to the OLDROAD spreadsheet to see which sources have been provided with connecting distances to the production locations. Only those sources with some numerical

Figure I.1

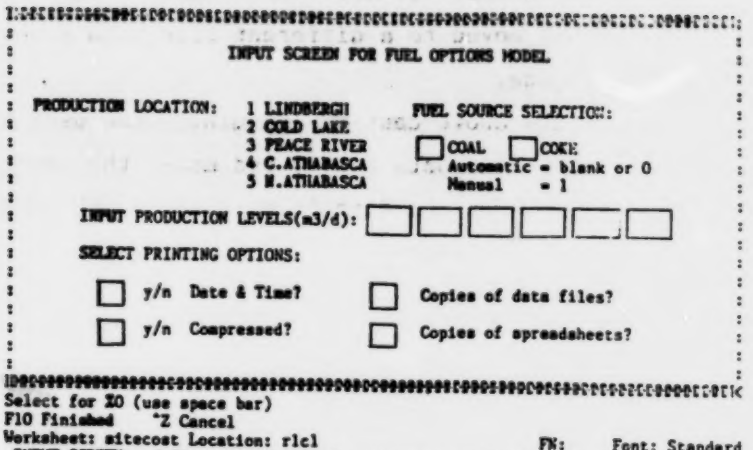


Figure I.2

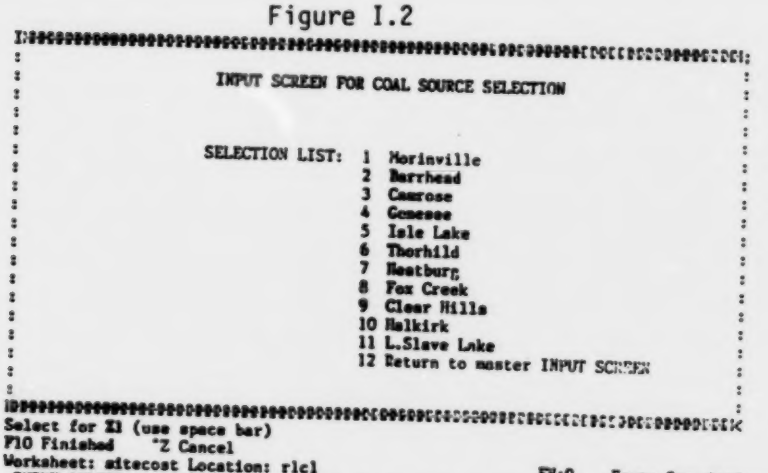
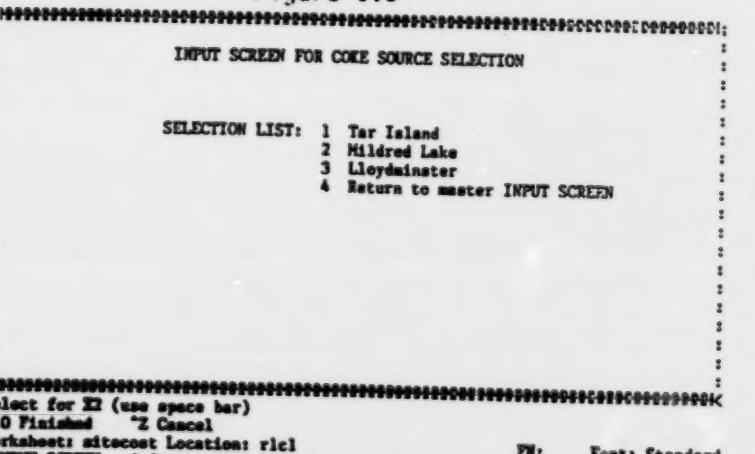


Figure I.3


INPUT SCREEN FOR COKE SOURCE SELECTION
SELECTION LIST:
1 Tar Island
2 Mildred Lake
3 Lloydminster
4 Return to master INPUT SCREEN
Select for I2 (use space bar)
F10 Finished ^Z Cancel
Worksheet: sitecost Location: r1c1
FN: Font: Standard
INPUT-SCREEN - define, modify, load, or erase a screen for data input

entry are fuel supply candidates. The user can accordingly control the number of candidates by the entries in the OLDROAD file. It is important to note that the entries in OLDROAD must always be less than or equal to the entries in all connecting distance files must be in corresponding positions (spreadsheet cells). If FUELOPTS fails to find any other connecting distance (NEWROAD, OLDRAIL, NEWRAIL, or PIPELINE) corresponding to an entry in OLDROAD the program will interrupt, state the problem, and permit the user to suspend execution until a data correction is made.

The observant user may note that some calculations are made in certain spreadsheets below the rows printed for report purposes. These additional calculations are to provide data for corresponding graphs.

2.2 Graph Generation

Graph generation within the SMART software system cannot be made automatic. Graph definition files must be defined manually. Nevertheless, sample files have been included with the user diskette, as examples, for user reference.

Each graph definition file requires one or more spreadsheet to be loaded as data sources for the subsequent graph construction. The corresponding graph definition files and spreadsheets are listed in Table I.2. The user can customize the existing graph definitions and create new ones without jeopardizing anything within FUELOPTS or the spreadsheets.

Graphs are generated on the screen, plotter, or matrix-printer through the GRAPHICS Command list 2 (confidence level 3). Changes to the graph definition files may be made through the DEFINE function.

TABLE I.2
GRAPH DEFINITION FILES

Graph Definition File Name	Data Source Spreadsheets	Status*	Graph Description
1. COALPRCE	PRICE	L	Mine gate coal price loaded versus strip ratio.
2. COSTCOAL	COMPARE	L	Cost components of steam raised from coal combustion versus production level.
3. COSTCOKE	COMPARE	L	Cost components of steam raised from coke combustion versus production level.
4. COSTGAS	COMPARE	L	Cost components of steam raised from gas combustion versus production level.
5. IRR	DIFFCOAL DIFFCOKE	L A	Internal Rate of Return versus production level (differential economics).
6. OPCOSTS	OPCOSTS	L	Operating cost as % of combustion mode capital cost versus production level.
7. PAYBACK	DIFFCOAL DIFFCOKE	L A	Payback from startup versus production level (differential economics).
8. STEAMCST	COMPARE	L	Unit cost of steam by fuel versus production level.
9. TOTCOAL	EQUICAP	L	Gas equivalent capital cost of coal fired steam facilities vs. production level.
10. TOTCOKE	EQUICAP	L	Gas equivalent capital cost of coke fired steam facilities versus production level.
11. UNITCOAL	EQUICAP	L	"One-of" gas equivalent capital cost of coal fired steam facilities versus production level.
12. UNITCOKE	EQUICAP	L	"One-of" gas equivalent capital cost of coke fired steam facilities versus production level.

*L=Loaded A= Activated

APPENDIX II

DELIVERED SOLID FUEL COSTS

DELIVERED COAL COST

Lindbergh

SOURCE INFORMATION						
Mine Location	Morinville					
HeatContent(GJ/T)	18.60					
Mine Price($/T)	11.70					
OIL PRODUCTION(m3/d)	800	1,600	2,400	3,200	4,800	6,400
COAL CONSUMED(K T/y)	147.3	294.5	441.8	589.1	883.6	1,178.1
TRANSPORT COSTS($/T)						
Truck	16.63	15.31	14.80	14.53	14.26	14.14
Rail	30.60	19.65	15.65	11.30	8.91	7.71
Pipeline	44.11	31.97	23.94	18.62	12.76	10.19
DELIVERED PRICES						
$/Tonne						
Truck	28.33	27.01	26.50	26.23	25.97	25.84
Rail	42.30	31.36	27.35	23.00	20.61	19.42
Pipeline	55.82	43.68	35.64	30.32	24.46	21.90
$/GJ						
Truck	1.52	1.45	1.42	1.41	1.40	1.39
Rail	2.27	1.69	1.47	1.24	1.11	1.04
Pipeline	3.00	2.35	1.92	1.63	1.32	1.18

DELIVERED COAL COST

Lindbergh

SOURCE INFORMATION						
Mine Location	Barrhead					
HeatContent(GJ/T)	18.20					
Mine Price($/T)	16.20					
OIL PRODUCTION(m3/d)	800	1,600	2,400	3,200	4,800	6,400
COAL CONSUMED(K T/y)	150.5	301.0	451.5	602.0	903.0	1,204.0
TRANSPORT COSTS($/T)						
Truck	18.49	18.17	17.98	17.87	17.76	17.72
Rail	38.14	24.16	19.10	13.79	10.81	9.33
Pipeline	53.89	38.83	28.94	22.46	15.41	12.37
DELIVERED PRICES						
$/Tonne						
Truck	34.68	34.37	34.18	34.07	33.96	33.92
Rail	54.34	40.36	35.30	29.98	27.00	25.52
Pipeline	70.09	55.02	45.14	38.65	31.60	28.57
$/GJ						
Truck	1.91	1.89	1.88	1.87	1.87	1.86
Rail	2.99	2.22	1.94	1.65	1.48	1.40
Pipeline	3.85	3.02	2.48	2.12	1.74	1.57

DELIVERED COAL COST

Lindbergh

SOURCE INFORMATION						
Mine Location	Camrose					
HeatContent(GJ/T)	18.30					
Mine Price($/T)	11.15					
OIL PRODUCTION(m3/d)	800	1,600	2,400	3,200	4,800	6,400
COAL CONSUMED(K T/y)	149.7	299.4	449.0	598.7	898.1	1,197.4
TRANSPORT COSTS($/T)						
Truck	15.59	13.94	13.34	13.02	12.70	12.56
Rail	29.07	19.32	15.68	11.26	9.02	7.91
Pipeline	29.25	21.10	15.75	12.23	8.39	6.73
DELIVERED PRICES						
$/Tonne						
Truck	26.74	25.09	24.48	24.17	23.85	23.70
Rail	40.21	30.46	26.83	22.41	20.17	19.06
Pipeline	40.39	32.25	26.89	23.37	19.53	17.87
$/GJ						
Truck	1.46	1.37	1.34	1.32	1.30	1.30
Rail	2.20	1.66	1.47	1.22	1.10	1.04
Pipeline	2.21	1.76	1.47	1.28	1.07	0.98

DELIVERED COAL COST

Lindbergh

SOURCE INFORMATION						
Mine Location	Genesee					
HeatContent(GJ/T)	20.20					
Mine Price($/T)	11.15					
OIL PRODUCTION(m3/d)	800	1,600	2,400	3,200	4,800	6,400
COAL CONSUMED(K T/y)	135.6	271.2	406.8	542.4	813.6	1,084.8
TRANSPORT COSTS($/T)						
Truck	20.38	20.05	19.83	19.70	19.56	19.51
Rail	42.14	26.73	21.06	15.33	11.98	10.28
Pipeline	55.76	41.33	31.46	24.70	16.92	13.28
DELIVERED PRICES						
$/Tonne						
Truck	31.52	31.19	30.98	30.85	30.71	30.65
Rail	53.29	37.88	32.21	26.48	23.13	21.42
Pipeline	66.91	52.47	42.60	35.85	28.07	24.43
$/GJ						
Truck	1.56	1.54	1.53	1.53	1.52	1.52
Rail	2.64	1.88	1.59	1.31	1.15	1.06
Pipeline	3.31	2.60	2.11	1.77	1.39	1.21

DELIVERED COAL COST

Lindbergh

SOURCE INFORMATION						
Mine Location	Isle Lake					
HeatContent(GJ/T)	19.00					
Mine Price($/T)	10.09					
OIL PRODUCTION(m3/d)	800	1,600	2,400	3,200	4,800	6,400
COAL CONSUMED(K T/y)	144.2	288.3	432.5	576.7	865.0	1,153.3
TRANSPORT COSTS($/T)						
Truck	23.64	21.45	20.63	20.19	19.76	19.56
Rail	35.54	23.31	18.76	13.54	10.77	9.38
Pipeline	60.37	44.02	33.09	25.80	17.67	14.05
DELIVERED PRICES						
$/Tonne						
Truck	33.73	31.54	30.72	30.28	29.85	29.65
Rail	45.64	33.41	28.85	23.63	20.86	19.47
Pipeline	70.46	54.11	43.19	35.89	27.77	24.14
$/GJ						
Truck	1.78	1.66	1.62	1.59	1.57	1.56
Rail	2.40	1.76	1.52	1.24	1.10	1.02
Pipeline	3.71	2.85	2.27	1.89	1.46	1.27

DELIVERED COAL COST

Lindbergh

SOURCE INFORMATION						
Mine Location	Thorhild					
HeatContent(GJ/T)	17.00					
Mine Price($/T)	13.58					
OIL PRODUCTION(m3/d)	800	1,600	2,400	3,200	4,800	6,400
COAL CONSUMED(K T/y)	161.1	322.3	483.4	644.5	966.8	1,289.0
TRANSPORT COSTS($/T)						
Truck	13.23	13.00	12.87	12.79	12.72	12.70
Rail	19.21	13.19	10.95	7.77	6.33	5.64
Pipeline	32.88	23.23	17.08	13.17	9.09	7.43
DELIVERED PRICES						
$/Tonne						
Truck	26.81	26.58	26.45	26.37	26.30	26.28
Rail	32.79	26.77	24.53	21.35	19.91	19.22
Pipeline	46.46	36.81	30.66	26.75	22.67	21.01
$/GJ						
Truck	1.58	1.56	1.56	1.55	1.55	1.55
Rail	1.93	1.57	1.44	1.26	1.17	1.13
Pipeline	2.73	2.17	1.80	1.57	1.33	1.24

DELIVERED COAL COST

Lindbergh

SOURCE INFORMATION						
Mine Location	Heatburg					
HeatContent(GJ/T)	18.00					
Mine Price($/T)	9.47					
OIL PRODUCTION(m3/d)	800	1,600	2,400	3,200	4,800	6,400
COAL CONSUMED(K T/y)	152.2	304.3	456.5	608.7	913.0	1,217.4
TRANSPORT COSTS($/T)						
Truck	21.56	21.20	20.98	20.85	20.72	20.68
Rail	34.94	24.60	20.61	14.67	12.05	10.76
Pipeline	30.33	36.15	26.89	20.84	14.31	11.52
DELIVERED PRICES						
$/Tonne						
Truck	31.04	30.67	30.45	30.32	30.19	30.15
Rail	44.41	34.07	30.08	24.15	21.52	20.23
Pipeline	59.81	45.62	36.36	30.31	23.78	21.00
$/GJ						
Truck	1.72	1.70	1.69	1.68	1.68	1.67
Rail	2.47	1.89	1.67	1.34	1.20	1.12
Pipeline	3.32	2.53	2.02	1.68	1.32	1.17

DELIVERED COAL COST

Lindbergh

SOURCE INFORMATION						
Mine Location	Halkirk					
HeatContent(GJ/T)	18.10					
Mine Price($/T)	14.83					
OIL PRODUCTION(m3/d)	800	1,600	2,400	3,200	4,800	6,400
COAL CONSUMED(K T/y)	151.3	302.7	454.0	605.3	908.0	1,210.7
TRANSPORT COSTS($/T)						
Truck	15.40	15.14	14.99	14.89	14.80	14.77
Rail	40.58	29.23	24.75	17.60	14.57	13.08
Pipeline	42.58	30.63	22.81	17.69	12.14	9.76
DELIVERED PRICES						
$/Tonne						
Truck	30.24	29.98	29.82	29.72	29.63	29.60
Rail	55.42	44.07	39.59	32.43	29.41	27.91
Pipeline	57.42	45.47	37.64	32.52	26.97	24.60
$/GJ						
Truck	1.67	1.66	1.65	1.64	1.64	1.64
Rail	3.06	2.43	2.19	1.79	1.62	1.54
Pipeline	3.17	2.51	2.08	1.80	1.49	1.36

DELIVERED COKE COST

Lindbergh

SOURCE INFORMATION						
Location	Lloydminster					
HeatContent(GJ/T)	29.86					
F.O.B. Price($/T)	20.00					
OIL PRODUCTION(m3/d)	800	1,600	2,400	3,200	4,800	6,400
COKE CONSUMED(K T/y)	91.7	183.5	275.2	366.9	550.4	733.9
TRANSPORT COSTS($/T)						
Truck	6.22	6.13	6.07	6.03	5.97	5.94
Rail	28.15	16.44	12.23	10.05	6.81	5.58
DELIVERED PRICES						
$/Tonne						
Truck	26.22	26.13	26.07	26.03	25.97	25.94
Rail	48.15	36.44	32.23	30.05	26.81	25.58
$/GJ						
Truck	0.88	0.88	0.87	0.87	0.87	0.87
Rail	1.61	1.22	1.08	1.01	0.90	0.86

DELIVERED COAL COST

Cold Lake

SOURCE INFORMATION						
Mine Location	Morinville					
HeatContent(GJ/T)	18.60					
Mine Price($/T)	11.70					
OIL PRODUCTION(m3/d)	800	1,600	2,400	3,200	4,800	6,400
COAL CONSUMED(K T/y)	119.4	238.8	358.2	477.6	716.4	955.2
TRANSPORT COSTS($/T)						
Truck	20.28	18.68	18.06	17.71	17.36	17.18
Rail	36.22	24.31	19.74	17.37	12.05	10.57
Pipeline	54.26	41.53	32.41	25.89	17.87	13.77
DELIVERED PRICES						
$/Tonne						
Truck	31.99	30.39	29.76	29.42	29.06	28.89
Rail	47.92	36.02	31.44	29.07	23.75	22.28
Pipeline	65.96	53.23	44.11	37.59	29.58	25.47
$/GJ						
Truck	1.72	1.63	1.60	1.58	1.56	1.55
Rail	2.58	1.94	1.69	1.56	1.28	1.20
Pipeline	3.55	2.86	2.37	2.02	1.59	1.37

DELIVERED COAL COST

Cold Lake

SOURCE INFORMATION						
Mine Location	Camrose					
HeatContent(GJ/T)	18.30					
Mine Price($/T)	11.15					
OIL PRODUCTION(m3/d)	800	1,600	2,400	3,200	4,800	6,400
COAL CONSUMED(K T/y)	121.4	242.7	364.1	485.4	728.2	970.9
TRANSPORT COSTS($/T)						
Truck	25.60	23.49	22.67	22.22	21.76	21.53
Rail	41.24	28.66	23.70	21.12	14.67	13.00
Pipeline	50.42	38.43	29.90	23.83	16.43	12.67
DELIVERED PRICES						
$/Tonne						
Truck	36.74	34.63	33.81	33.37	32.90	32.68
Rail	52.39	39.81	34.85	32.26	25.81	24.15
Pipeline	61.56	49.58	41.05	34.97	27.57	23.82
$/GJ						
Truck	2.01	1.89	1.85	1.82	1.80	1.79
Rail	2.86	2.18	1.90	1.76	1.41	1.32
Pipeline	3.36	2.71	2.24	1.91	1.51	1.30

DELIVERED COAL COST

Cold Lake

SOURCE INFORMATION						
Mine Location	Isle Lake					
HeatContent(GJ/T)	19.00					
Mine Price($/T)	10.09					
OIL PRODUCTION(m3/d)	800	1,600	2,400	3,200	4,800	6,400
COAL CONSUMED(K T/y)	116.9	233.8	350.7	467.6	701.3	935.1
TRANSPORT COSTS($/T)						
Truck	26.75	24.12	23.13	22.39	22.04	21.77
Rail	55.82	36.64	29.38	25.61	17.77	15.47
Pipeline	72.77	55.98	43.87	35.14	24.31	18.69
DELIVERED PRICES						
$/Tonne						
Truck	36.84	34.22	33.22	32.69	32.13	31.86
Rail	65.91	46.73	39.47	35.70	27.86	25.56
Pipeline	82.86	66.07	53.96	45.23	34.41	28.78
$/GJ						
Truck	1.94	1.80	1.75	1.72	1.69	1.68
Rail	3.47	2.46	2.08	1.88	1.47	1.35
Pipeline	4.36	3.48	2.84	2.38	1.81	1.51

DELIVERED COAL COST

Cold Lake

SOURCE INFORMATION						
Mine Location	Therhild					
HeatContent(GJ/T)	17.00					
Mine Price($/T)	13.58					
OIL PRODUCTION(m3/d)	800	1,600	2,400	3,200	4,800	6,400
COAL CONSUMED(K T/y)	130.6	261.3	391.9	522.6	783.9	1,045.1
TRANSPORT COSTS($/T)						
Truck	13.90	13.68	13.54	13.44	13.34	13.30
Rail	31.50	20.80	16.79	12.55	10.14	8.90
Pipeline	41.12	30.78	23.60	18.62	12.77	9.96
DELIVERED PRICES						
$/Tonne						
Truck	27.48	27.26	27.12	27.02	26.92	26.88
Rail	45.08	34.38	30.37	26.13	23.72	22.48
Pipeline	54.70	44.36	37.18	32.20	26.35	23.54
$/GJ						
Truck	1.62	1.60	1.60	1.59	1.58	1.58
Rail	2.65	2.02	1.79	1.54	1.40	1.32
Pipeline	3.22	2.61	2.19	1.89	1.55	1.38

DELIVERED COKE COST

Cold Lake

SOURCE INFORMATION						
Location	Lloydminster					
HeatContent(GJ/T)	29.86					
F.O.B. Price($/T)	20.00					
OIL PRODUCTION(m3/d)	800	1,600	2,400	3,200	4,800	6,400
COKE CONSUMED(K T/y)	74.4	148.8	223.1	297.5	446.3	595.0
TRANSPORT COSTS($/T)						
Truck	14.04	13.87	13.74	13.63	13.49	13.41
Rail	76.38	44.74	33.44	27.52	21.41	15.90
DELIVERED PRICES						
$/Tonne						
Truck	34.04	33.87	33.74	33.63	33.49	33.41
Rail	96.38	64.74	53.44	47.52	41.41	35.90
$/GJ						
Truck	1.14	1.13	1.13	1.13	1.12	1.12
Rail	3.23	2.17	1.79	1.59	1.39	1.20

DELIVERED COAL COST

Peace River

SOURCE INFORMATION						
Mine Location	Morinville					
HeatContent(GJ/T)	18.60					
Mine Price($/T)	11.70					
OIL PRODUCTION(m3/d)	800	1,600	2,400	3,200	4,800	6,400
COAL CONSUMED(K T/y)	159.2	318.4	477.6	636.8	955.2	1,273.6
TRANSPORT COSTS($/T)						
Truck	31.52	30.02	29.39	29.05	28.72	28.59
Rail	54.07	35.08	28.19	20.17	16.03	14.01
Pipeline	75.95	53.85	39.69	30.63	21.11	17.20
DELIVERED PRICES						
$/Tonne						
Truck	43.22	41.72	41.09	40.75	40.43	40.29
Rail	65.78	46.78	39.89	31.87	27.73	25.71
Pipeline	87.66	65.55	51.40	42.33	32.81	28.91
$/GJ						
Truck	2.32	2.24	2.21	2.19	2.17	2.17
Rail	3.54	2.52	2.14	1.71	1.49	1.38
Pipeline	4.71	3.52	2.76	2.28	1.76	1.55

DELIVERED COAL COST

Peace River

SOURCE INFORMATION						
Mine Location	Barrhead					
HeatContent(GJ/T)	18.20					
Mine Price($/T)	16.20					
OIL PRODUCTION(m3/d)	800	1,600	2,400	3,200	4,800	6,400
COAL CONSUMED(K T/y)	162.7	325.4	488.1	650.8	976.2	1,301.6
TRANSPORT COSTS($/T)						
Truck	24.30	23.88	23.64	23.50	23.37	23.33
Rail	58.89	38.40	30.98	22.10	17.62	15.46
Pipeline	67.71	47.70	35.01	26.96	18.63	15.27
DELIVERED PRICES						
$/Tonne						
Truck	40.49	40.08	39.83	39.69	39.57	39.52
Rail	75.09	54.59	47.18	38.30	33.82	31.65
Pipeline	83.91	63.90	51.21	43.16	34.82	31.47
$/GJ						
Truck	2.22	2.20	2.19	2.18	2.17	2.17
Rail	4.13	3.00	2.59	2.10	1.86	1.74
Pipeline	4.61	3.51	2.81	2.37	1.91	1.73

DELIVERED COAL COST

Peace River

SOURCE INFORMATION						
Mine Location	Isle Lake					
HeatContent(GJ/T)	19.00					
Mine Price($/T)	10.09					
OIL PRODUCTION(m3/d)	800	1,600	2,400	3,200	4,800	6,400
COAL CONSUMED(K T/y)	155.9	311.7	467.6	623.4	935.1	1,246.8
TRANSPORT COSTS($/T)						
Truck	30.10	27.93	27.09	26.64	26.21	26.01
Rail	62.10	42.09	34.61	24.68	19.98	17.68
Pipeline	80.97	57.76	42.75	33.06	22.74	18.42
DELIVERED PRICES						
$/Tonne						
Truck	40.19	38.02	37.18	36.73	36.30	36.10
Rail	72.19	52.18	44.70	34.77	30.07	27.78
Pipeline	91.06	67.85	52.85	43.15	32.83	28.52
$/GJ						
Truck	2.12	2.00	1.96	1.93	1.91	1.90
Rail	3.80	2.75	2.35	1.83	1.58	1.46
Pipeline	4.79	3.57	2.78	2.27	1.73	1.50

DELIVERED COAL COST

Peace River

SOURCE INFORMATION						
Mine Location	Fox Creek					
HeatContent(GJ/T)	16.10					
Mine Price($/T)	10.45					
OIL PRODUCTION(m3/d)	800	1,600	2,400	3,200	4,800	6,400
COAL CONSUMED(K T/y)	183.9	367.9	551.8	735.7	1,103.6	1,471.4
TRANSPORT COSTS($/T)						
Truck	22.55	18.87	17.58	16.93	16.30	15.99
Rail	76.43	42.48	28.58	22.55	16.46	13.49
Pipeline	41.65	28.27	20.27	15.49	10.93	9.30
DELIVERED PRICES						
$/Tonne						
Truck	33.00	29.32	28.03	27.38	26.75	26.44
Rail	86.88	52.93	39.03	33.00	26.91	23.94
Pipeline	52.10	38.72	30.72	25.94	21.38	19.76
$/GJ						
Truck	2.05	1.82	1.74	1.70	1.66	1.64
Rail	5.40	3.29	2.42	2.05	1.67	1.49
Pipeline	3.24	2.40	1.91	1.61	1.33	1.23

DELIVERED COAL COST

Peace River

SOURCE INFORMATION						
Mine Location	Clear Hills					
HeatContent(GJ/T)	16.00					
Mine Price($/T)	15.30					
OIL PRODUCTION(m3/d)	800	1,600	2,400	3,200	4,800	6,400
COAL CONSUMED(K T/y)	185.1	370.2	555.2	740.3	1,110.5	1,480.6
TRANSPORT COSTS($/T)						
Truck	37.00	24.51	20.30	18.20	16.10	15.06
Rail	66.01	35.12	23.34	18.20	12.84	10.20
Pipeline	25.96	17.39	12.60	9.63	6.80	5.80
DELIVERED PRICES						
$/Tonne						
Truck	52.29	39.81	35.60	33.49	31.40	30.36
Rail	81.30	50.41	38.83	33.50	28.14	25.50
Pipeline	41.26	32.88	27.89	24.92	22.10	21.10
$/GJ						
Truck	3.27	2.49	2.23	2.09	1.96	1.90
Rail	5.08	3.15	2.43	2.09	1.76	1.59
Pipeline	2.58	2.06	1.74	1.56	1.38	1.32

DELIVERED COKE COST

Peace River

SOURCE INFORMATION						
Location	Tar Island					
HeatContent(GJ/T)	33.50					
F.O.B. Price($/T)	17.25					
OIL PRODUCTION(m3/d)	800	1,600	2,400	3,200	4,800	6,400
COKE CONSUMED(K T/y)	88.4	176.8	265.2	353.6	530.4	707.2
TRANSPORT COSTS($/T)						
Truck	44.80	44.21	43.76	43.43	43.00	42.77
Rail	60.39	52.40	47.22	43.85	31.79	28.98
DELIVERED PRICES						
$/Tonne						
Truck	62.05	61.46	61.01	60.68	60.25	60.02
Rail	77.64	69.65	64.47	61.10	49.04	46.23
$/GJ						
Truck	1.85	1.83	1.82	1.81	1.80	1.79
Rail	2.32	2.08	1.92	1.82	1.46	1.38

DELIVERED COAL COST

C.Athabasca

SOURCE INFORMATION						
Mine Location	Morinville					
HeatContent(GJ/T)	18.60					
Mine Price($/T)	11.70					
OIL PRODUCTION(m3/d)	800	1,600	2,400	3,200	4,800	6,400
COAL CONSUMED(K T/y)	199.0	398.0	597.0	796.0	1,194.0	1,592.1
TRANSPORT COSTS($/T)						
Truck	21.78	20.63	20.18	19.95	19.75	19.66
Rail	51.19	34.29	23.95	20.50	17.03	15.44
Pipeline	58.40	38.65	27.34	20.87	15.03	13.12
DELIVERED PRICES						
$/Tonne						
Truck	33.49	32.33	31.88	31.66	31.45	31.37
Rail	62.90	45.99	35.66	32.21	28.73	27.15
Pipeline	70.10	50.36	39.05	32.57	26.73	24.82
$/GJ						
Truck	1.80	1.74	1.71	1.70	1.69	1.69
Rail	3.38	2.47	1.92	1.73	1.54	1.46
Pipeline	3.77	2.71	2.10	1.75	1.44	1.33

DELIVERED COAL COST

C.Athabasca

SOURCE INFORMATION						
Mine Location	Barrhead					
HeatContent(GJ/T)	18.20					
Mine Price($/T)	16.20					
OIL PRODUCTION(m3/d)	800	1,600	2,400	3,200	4,800	6,400
COAL CONSUMED(K T/y)	203.4	406.8	610.1	813.5	1,220.3	1,627.0
TRANSPORT COSTS($/T)						
Truck	18.36	18.03	17.87	17.78	17.72	17.71
Rail	57.19	38.11	26.57	22.70	18.84	17.08
Pipeline	57.83	38.01	26.80	20.45	14.83	13.03
DELIVERED PRICES						
$/Tonne						
Truck	34.55	34.23	34.06	33.98	33.92	33.90
Rail	73.39	54.30	42.76	38.90	35.04	33.27
Pipeline	74.03	54.21	42.99	36.65	31.03	29.23
$/GJ						
Truck	1.90	1.88	1.87	1.87	1.86	1.86
Rail	4.03	2.98	2.35	2.14	1.93	1.83
Pipeline	4.07	2.98	2.36	2.01	1.70	1.61

DELIVERED COAL COST

C.Athabasca

SOURCE INFORMATION						
Mine Location	Camrose					
HeatContent(GJ/T)	18.30					
Mine Price($/T)	11.15					
OIL PRODUCTION(m3/d)	800	1,600	2,400	3,200	4,800	6,400
COAL CONSUMED(K T/y)	202.3	404.5	606.8	809.1	1,213.6	1,618.2
TRANSPORT COSTS($/T)						
Truck	33.88	32.26	31.62	31.30	31.01	30.90
Rail	52.02	36.24	25.42	22.06	18.68	17.18
Pipeline	69.97	46.07	32.51	24.81	17.96	15.75
DELIVERED PRICES						
$/Tonne						
Truck	45.03	43.40	42.77	42.44	42.16	42.04
Rail	63.16	47.39	36.57	33.20	29.83	28.32
Pipeline	81.12	57.22	43.65	35.95	29.10	26.89
$/GJ						
Truck	2.46	2.37	2.34	2.32	2.30	2.30
Rail	3.45	2.59	2.00	1.81	1.63	1.55
Pipeline	4.43	3.13	2.39	1.96	1.59	1.47

DELIVERED COAL COST

C.Athabasca

SOURCE INFORMATION						
Mine Location	Isle Lake					
HeatContent(GJ/T)	19.00					
Mine Price($/T)	10.09					
OIL PRODUCTION(m3/d)	800	1,600	2,400	3,200	4,800	6,400
COAL CONSUMED(K T/y)	194.8	389.6	584.5	779.3	1,168.9	1,558.5
TRANSPORT COSTS($/T)						
Truck	30.81	28.94	28.22	27.86	27.52	27.38
Rail	56.34	38.60	27.09	23.36	19.58	17.86
Pipeline	72.15	48.09	34.14	26.05	18.65	16.17
DELIVERED PRICES						
$/Tonne						
Truck	40.90	39.03	38.31	37.95	37.62	37.47
Rail	66.43	48.70	37.18	33.45	29.67	27.95
Pipeline	82.25	58.18	44.23	36.15	28.75	26.26
$/GJ						
Truck	2.15	2.05	2.02	2.00	1.98	1.97
Rail	3.50	2.56	1.96	1.76	1.56	1.47
Pipeline	4.33	3.06	2.33	1.90	1.51	1.38

DELIVERED COAL COST

C.Athabasca

SOURCE INFORMATION						
Mine Location	Thorhild					
HeatContent(GJ/T)	17.00					
Mine Price($/T)	13.58					
OIL PRODUCTION(m3/d)	800	1,600	2,400	3,200	4,800	6,400
COAL CONSUMED(K T/y)	217.7	435.5	653.2	870.9	1,306.4	1,741.9
TRANSPORT COSTS($/T)						
Truck	17.10	16.80	16.65	16.58	16.53	16.52
Rail	41.83	27.84	19.32	16.52	13.76	12.52
Pipeline	47.34	30.43	21.24	16.24	12.05	10.81
DELIVERED PRICES						
$/Tonne						
Truck	30.68	30.38	30.23	30.16	30.11	30.10
Rail	55.41	41.42	32.90	30.10	27.34	26.10
Pipeline	60.92	44.01	34.82	29.82	25.63	24.39
$/GJ						
Truck	1.80	1.79	1.78	1.77	1.77	1.77
Rail	3.26	2.44	1.94	1.77	1.61	1.54
Pipeline	3.58	2.59	2.03	1.75	1.51	1.43

DELIVERED COKE COST

C.Athabasca

SOURCE INFORMATION						
Location	Tar Island					
HeatContent(GJ/T)	33.50					
F.O.B. Price($/T)	17.25					
OIL PRODUCTION(m3/d)	800	1,600	2,400	3,200	4,800	6,400
COKE CONSUMED(K T/y)	110.5	221.0	331.5	442.0	663.0	883.9
TRANSPORT COSTS($/T)						
Truck	5.58	5.50	5.44	5.40	5.35	5.33
Rail	73.16	39.26	27.64	21.78	14.56	11.48
DELIVERED PRICES						
$/Tonne						
Truck	22.83	22.75	22.69	22.65	22.60	22.58
Rail	90.41	56.51	44.89	39.03	31.81	28.73
$/GJ						
Truck	0.68	0.68	0.68	0.68	0.67	0.67
Rail	2.70	1.69	1.34	1.17	0.95	0.86

DELIVERED COKE COST

C.Athabasca

SOURCE INFORMATION						
Location	Mildred Lake					
HeatContent(GJ/T)	29.50					
F.O.B. Price($/T)	17.25					
OIL PRODUCTION(m3/d)	800	1,600	2,400	3,200	4,800	6,400
COKE CONSUMED(K T/y)	125.5	251.0	376.4	501.9	752.9	1,003.8
TRANSPORT COSTS($/T)						
Truck	6.18	6.09	6.02	5.98	5.93	5.91
Rail	69.71	37.51	26.51	19.70	13.96	11.05
DELIVERED PRICES						
$/Tonne						
Truck	23.43	23.34	23.27	23.23	23.18	23.16
Rail	86.96	54.76	43.76	36.95	31.21	28.30
$/GJ						
Truck	0.79	0.79	0.79	0.79	0.79	0.79
Rail	2.95	1.86	1.48	1.25	1.06	0.96

DELIVERED COAL COST

N.Athabasca

SOURCE INFORMATION						
Mine Location	Morinville					
HeatContent(GJ/T)	18.60					
Mine Price($/T)	11.70					
OIL PRODUCTION(m3/d)	800	1,600	2,400	3,200	4,800	6,400
COAL CONSUMED(K T/y)	199.0	398.0	597.0	796.0	1,194.0	1,592.1
TRANSPORT COSTS($/T)						
Truck	29.13	27.85	27.33	27.07	26.84	26.75
Rail	55.93	37.90	26.52	22.79	19.03	17.33
Pipeline	79.54	52.65	37.24	28.42	20.47	17.86
DELIVERED PRICES						
$/Tonne						
Truck	40.83	39.55	39.03	38.77	38.54	38.45
Rail	67.63	49.60	38.22	34.49	30.74	29.03
Pipeline	91.24	64.35	48.95	40.12	32.18	29.57
$/GJ						
Truck	2.20	2.13	2.10	2.08	2.07	2.07
Rail	3.64	2.67	2.05	1.85	1.65	1.56
Pipeline	4.91	3.46	2.63	2.16	1.73	1.59

DELIVERED COAL COST

N.Athabasca

SOURCE INFORMATION						
Mine Location	Camrose					
HeatContent(GJ/T)	18.30					
Mine Price($/T)	11.15					
OIL PRODUCTION(m3/d)	800	1,600	2,400	3,200	4,800	6,400
COAL CONSUMED(K T/y)	202.3	404.5	606.8	809.1	1,213.6	1,618.2
TRANSPORT COSTS($/T)						
Truck	40.77	39.02	38.32	37.97	37.66	37.54
Rail	60.97	41.91	29.35	25.35	21.34	19.54
Pipeline	90.96	59.89	42.26	32.25	23.34	20.47
DELIVERED PRICES						
$/Tonne						
Truck	51.91	50.17	49.47	49.11	48.80	48.68
Rail	72.12	53.06	40.50	36.49	32.49	30.68
Pipeline	102.11	71.04	53.40	43.39	34.49	31.62
$/GJ						
Truck	2.84	2.74	2.70	2.68	2.67	2.66
Rail	3.94	2.90	2.21	1.99	1.78	1.68
Pipeline	5.58	3.88	2.92	2.37	1.88	1.73

DELIVERED COAL COST

N.Athabasca

SOURCE INFORMATION						
Mine Location	Isle Lake					
HeatContent(GJ/T)	19.00					
Mine Price($/T)	10.09					
OIL PRODUCTION(m3/d)	800	1,600	2,400	3,200	4,800	6,400
COAL CONSUMED(K T/y)	194.8	389.6	584.5	779.3	1,168.9	1,558.5
TRANSPORT COSTS($/T)						
Truck	37.70	35.70	34.93	34.53	34.17	34.02
Rail	67.17	45.28	31.70	27.18	22.62	20.32
Pipeline	93.50	62.31	44.23	33.76	24.17	20.95
DELIVERED PRICES						
$/Tonne						
Truck	47.79	45.80	45.02	44.62	44.26	44.11
Rail	77.26	55.37	41.79	37.28	32.71	30.62
Pipeline	103.59	72.40	54.33	43.85	34.26	31.04
$/GJ						
Truck	2.52	2.41	2.37	2.35	2.33	2.32
Rail	4.07	2.91	2.20	1.96	1.72	1.61
Pipeline	5.45	3.81	2.86	2.31	1.80	1.63

DELIVERED COAL COST

N.Athabasca

SOURCE INFORMATION						
Mine Location	Thorhild					
HeatContent(GJ/T)	17.00					
Mine Price($/T)	13.58					
OIL PRODUCTION(m3/d)	800	1,600	2,400	3,200	4,800	6,400
COAL CONSUMED(K T/y)	217.7	435.5	653.2	870.9	1,306.4	1,741.9
TRANSPORT COSTS($/T)						
Truck	23.95	23.52	23.32	23.22	23.15	23.13
Rail	48.87	32.47	22.53	19.25	16.03	14.57
Pipeline	67.63	43.47	30.34	23.20	17.21	15.44
DELIVERED PRICES						
$/Tonne						
Truck	37.53	37.10	36.90	36.80	36.73	36.71
Rail	62.45	46.05	36.11	32.83	29.61	28.15
Pipeline	81.21	57.05	43.92	36.78	30.79	29.02
$/GJ						
Truck	2.21	2.18	2.17	2.16	2.16	2.16
Rail	3.67	2.71	2.12	1.93	1.74	1.66
Pipeline	4.78	3.36	2.58	2.16	1.81	1.71

DELIVERED COKE COST

N.Athabasca

SOURCE INFORMATION						
Location	Tar Island					
HeatContent(GJ/T)	33.50					
F.O.B. Price($/T)	17.25					
OIL PRODUCTION(m3/d)	800	1,600	2,400	3,200	4,800	6,400
COKE CONSUMED(K T/y)	110.5	221.0	331.5	442.0	663.0	883.9
TRANSPORT COSTS($/T)						
Truck	4.96	4.89	4.83	4.80	4.76	4.74
Rail	55.64	29.14	20.15	15.63	10.44	8.11
DELIVERED PRICES						
$/Tonne						
Truck	22.21	22.14	22.08	22.05	22.01	21.99
Rail	72.89	46.39	37.40	32.88	27.69	25.36
$/GJ						
Truck	0.66	0.66	0.66	0.66	0.66	0.66
Rail	2.18	1.38	1.12	0.98	0.83	0.76

DELIVERED COKE COST

N.Athabasca

SOURCE INFORMATION						
Location	Mildred Lake					
HeatContent(GJ/T)	29.50					
F.O.B. Price($/T)	17.25					
OIL PRODUCTION(m3/d)	800	1,600	2,400	3,200	4,800	6,400
COKE CONSUMED(K T/y)	125.5	251.0	376.4	501.9	752.9	1,003.8
TRANSPORT COSTS($/T)						
Truck	4.33	4.26	4.22	4.19	4.15	4.14
Rail	49.35	25.93	17.99	13.41	9.33	7.27
DELIVERED PRICES						
$/Tonne						
Truck	21.58	21.51	21.47	21.44	21.40	21.39
Rail	66.60	43.18	35.24	30.66	26.58	24.52
$/GJ						
Truck	0.73	0.73	0.73	0.73	0.73	0.73
Rail	2.26	1.46	1.19	1.04	0.90	0.83

APPENDIX III

COAL PROPERTY DATA SHEETS

CONTRIBUTORS:

PanCanadian Petroleum	-	Isle Lake
Crows Nest Resources	-	Camrose
	-	Fox Creek
	-	Pickardville
	-	Legal
Fording Coal Limited	-	Camrose-Ryley
	-	Heatburg
	-	Genesee
	-	Thorhild
	-	Morinville
Luscar Ltd.	-	Barrhead
	-	Lesser Slave Lake
	-	Tofield
	-	Halkirk
	-	Castor
TransAlta Utilities	-	Isle Lake

COAL DATA SHEET I
Reserves & Quality

Company: PanCanadian Petroleum Limited Phone: 290-2820

Contact: R. H. Duthie

Coal Property:

Field: Wabamun (Isle Lake)

Location: Twps 52-55 Rges 6-7 W5M

Property Status: (Three separate blocks; a fourth block exists west of the Pembina River)

Production:
Development:
Completed Feasibility:
Ongoing Exploration
Early Exploration: Data based on approx. 136 holes drilled in 1972 & 1976.
Rate:
Possible Production Date:

Geology & Coal Seams: Ardley Coal Zone - Scolland Formation

Seam Names	Thickness	Depth	Tonnage
Generally 2 or 3 seams Names vary (Ardley Coal Zone)	Approximately 10 ft. 12 ft. 4 ft.	200 ft. maximum	

Reserves:	Tonnage Raw Coal	Mining Ratio (bcm/trc)
Committed: Proven: Probable: Possible:	49.5 x 10^6 tons*	9.49 cu yd/ton

*PanCanadian coal only - see EUPC for approximate field reserves.

ROM Coal Quality:(as received)

H_2O: 18.4
Ash: 21.2
VM: 25.8
VC: 34.6
Eq. M: 23.5

Heat Content: 7395 BTU/lb
Sulphur: .23
Size Consist:

Access to Transport Infrastructure:

COAL DATA SHEET I
Reserves & Quality

Company: CROWS NEST RESOURCES Phone: 232-4355

Contact: B. RYAN

Coal Property: CAMROSE

Field: S. DUSTY LK., OHATON, DRIEDMEAT LK.

Location: TWP. 45-47, RGE. 17-18 & TWP. 45-46, RGE. 19 W. 4M.

Property Status:

Production: NONE
Development: NONE
Completed Feasibility:
Ongoing Exploration: NONE AT PRESENT
Early Exploration: SPROULE & ASSOC. 1977; MONENCO
Rate:
Possible Production Date: N/A

Geology & Coal Seams:

Seam Names		Thickness	Depth	Tonnage
4	2.84 - 7.53m.	0 - 0.72m.	in place to 46m.	123.4×10^6 tonnes
3		0 - 0.54		
2		0.53 - 1.64		
1		1.46 - 2.16		
0		0.85 - 1.39		
0_1		0 - 1.08		

Reserves:

	Tonnage Raw Coal	Mining Ratio (bcm/trc)
Committed:		
Proven:		
Probable:	123.4×10^6 tonnes	
Possible:		

ROM Coal Quality:

H_2O:	26.5	Heat Content:	4518 cal./gm.
Ash:	9.5	Sulphur:	0.50
VM:	27.4	Size Consist:	
FC:	35.2		

Access to Transport Infrastructure:

Rail access adjacent to southern end of property: CPR

COAL DATA SHEET I
Reserves & Quality

Company: CROWS NEST RESOURCES Phone: 232-4355

Contact: B. RYAN

Coal Property: FOX CREEK

Field: 7 Field Summary

Location: T. 63-66, R. 15-23

Property Status:

Production:
Development:
Completed Feasibility: — mining study (1980) on blocks III A and III B
Ongoing Exploration
Early Exploration:
Rate:
Possible Production Date:

Geology & Coal Seams:

~~Seam~~ Property Names	Thickness	Depth	Tonnage (Strip mineable in f
Simonette	max.	53.3m	68 x 10^6 tonnes
IA			41
Giroux L. (IB)			104
Meekwap W. (III A)			172
Meekwap E (III C)			109
IV			68
Iosegun L. (II)			307

Reserves:

	Tonnage Raw Coal	Mining Ratio (bcm/trc)
Committed:		
Proven:		
Probable:		
Possible:		

11/1

ROM Coal Quality:

H_2O:
Ash:
VM:
VC:

Heat Content:
Sulphur:
Size Consist:

Access to Transport Infrastructure:

COAL DATA SHEET I
Reserves & Quality

Company: CROWS NEST RESOURCES Phone: 232-4355

Contact: B. RYAN

Coal Property: PICKARDVILLE - LEGAL

Field: LEGAL

Location: TWP. 55-59, RGE. 24-26 W4M.

Property Status:

Production:
Development:
Completed Feasibility:
Ongoing Exploration
Early Exploration: Sproule & Assoc.
Rate:
Possible Production Date:

Geology & Coal Seams:

Seam Names	Thickness	Depth	Tonnage
6			44.4
5			54.0
4 U/L		to 46m.	23.0/5.7
3			56.1
2			215.6
1 U/L			17.6/49.5

Reserves:

	Tonnage Raw Coal	Mining Ratio (bcm/trc)
Committed:		
Proven:		
Probable:		
Possible:		

ROM Coal Quality: from 2 Seam

H_2O:	27.0	Heat Content:	4339 cal/gm.
Ash:	11.0	Sulphur:	0.34
VM:	27.0	Size Consist:	
FC:	35.0		

Access to Transport Infrastructure:

COAL DATA SHEET I

Reserves & Quality

Company: Fording Coal Limited **Phone:** 264-1063

Contact: D.J. Shyluk

Coal Property: Camrose-Ryley

Field: Lower Horse Shoe Canyon

Location: Camrose, Alberta Township 47 to 51, Ranges 17 to 19, West of 4th

Property Status:

Production: Nil
Development: Nil
Completed Feasibility: Definitive feasibility study 1976
Ongoing Exploration: As required
Early Exploration:
Rate: As required
Possible Production Date: 18 months lead time

Geology & Coal Seams:

Seam Names	Thickness	Depth	Tonnage x 10^6 tonnes
F (Burnstad Seam)	1.0m	Max.	35.7
J	0.92m	45.7m	12.3
M	1.43m	45.7m	67.4
P	0.62m		0.7
Q (Dods Seam)	1.63m	45.7m	190.5
Q1	0.70m		8.3

Reserves:

	Tonnage Raw Coal	Mining Ratio (bcm/trc)
Committed:		
Proven:	237 x 10^6 tonnes	6.4 (Net Fording 120.8 x 10^6 tonnes)
Probable:		
Possible:		

ROM Coal Quality:

H_2O:	26.0	Heat Content:	4163 KCal/Kg
Ash:	12.5	Sulphur:	0.6
VM:	27.5	Size Consist:	50mm x 0
VC:	34.0		

Access to Transport Infrastructure: 16 Km to CNR line at Ryley
29 Km to CPR at Camrose

COAL DATA SHEET I
Reserves & Quality

Company: Fording Coal Limited **Phone:** 264-1063

Contact: D.J. Shyluk

Coal Property: Heatburg

Field: Ardley

Location: 10 kilometres south of Alix & 36 kilometres east of Red Deer

Property Status:

Production:
Development: Preliminary disclosure issued 1982. Deferred 1983.
Completed Feasibility: 1982
Ongoing Exploration As required
Early Exploration:
Rate: Up to 10×10^6 tonnes per year
Possible Production Date: Preliminary Disclosure may eventually be accepted. 18 month lead time for 1st production.

Geology & Coal Seams: (Insitu)

Seam Names	Thickness	Depth	Tonnage $\times 10^6$
Upper Seam	1.641		133.50
Mid A	1.516	Max.	168.38
Mid B	1.705	45.7m	187.99
Lower	0.662		71.07

Reserves:

	Tonnage Raw Coal	Mining Ratio (bcm/trc)
Committed:		
Proven:	476.8×10^6	4.5/1
Probable:		
Possible:		

ROM Coal Quality:

H_2O:	18.0	Heat Content:	3809 KCal/Kg
Ash:	26.53	Sulphur:	0.30
VM:	23.94	Size Consist:	50 x 0mm
VC:	31.55		

Access to Transport Infrastructure: Rail Siding at Alix on C.P. Rail

COAL DATA SHEET 1
Reserves & Quality

Company: Fording Coal Limited **Phone:** 264-1063

Contact: J.L. Popowich

Coal Property: Genesee

Field: Ardley Coal Zone

Location: Genesee

Property Status:

Production: Coal Property is licenced.
Development: Coal Property is licenced.
Completed Feasibility: 1982
Ongoing Exploration: Development drilling only necessary immediately ahead of production.
Early Exploration:
Rate: 3×10^6 tonnes per year
Possible Production Date: 1986

Geology & Coal Seams:

Seam Names	Thickness	Depth	Tonnage (x 10^6 tonnes)
High Seam			19.083
Upper Main	Min.	<50m	75.718
Upper Main 1	0.6m		4.839
Lower Main			43.174
		Insitu	142.814

Reserves:

	Tonnage Raw Coal	Mining Ratio (bcm/trc)
Committed:		
Proven:	121.39	5.95
Probable:		
Possible:		

ROM Coal Quality:

H_2O:	20.0	Heat Content:	4833 KCal/Kg
Ash:	11.94	Sulphur:	0.22
VM:	20.40	Size Consist:	50mm x 0
VC:	39.96		

Access to Transport Infrastructure: 16 Km from Warburg on CPR to Leduc

COAL DATA SHEET I
Reserves & Quality

Company: Fording Coal Limited **Phone:** 264-1063

Contact: D.J. Shyluk

Coal Property: Thorhild

Field: Wapiti Formation

Location: Township 59 & 60, Range 20 West of the 4th Meridina (437 ha in 3 Crown coal leases)

Property Status:

Production: Nil
Development: Nil
Completed Feasibility: Nil
Ongoing Exploration: As warranted
Early Exploration: 1977 Exploration Program (16 rotary holes with Geophysics).
Rate:
Possible Production Date:

Geology & Coal Seams:

Seam Names	Thickness	Depth	Tonnage
Boundary Seam	1.7m	5.5m	0.96×10^6 tonnes
Pay Seam	1.6m	6.1m	3.23×10^6 tonnes

Reserves:

	Tonnage Raw Coal	Mining Ratio (bcm/trc)
Committed:		
Proven:	Nil	
Probable:	4.19×10^6 tonnes	3.62
Possible:		

ROM Coal Quality: Anticipated

H_2O:	25.3	Heat Content:	4800 KCal/Kg
Ash:	7.1	Sulphur:	0.3
VM:	28.6	Size Consist:	50mm x 0
VC:	39.0		

Access to Transport Infrastructure: 24 kilometres from Radway on CNR line to Grand Centre (near Cold Lake)

COAL DATA SHEET I
Reserves & Quality

Company: Fording Coal Limited **Phone:** 264-1063

Contact: D.J. Shyluk

Coal Property: Morinville

Field: Clover Bar Coal Zone Edmonton Formation

Location: Township 54, Ranges 25 & 26, ; Township 55, Ranges 25 & 26; and Township 56, Ranges 25 & 26, West of the 4th Meridian

Property Status:

Production: Nil
Development: Nil
Completed Feasibility: Nil
Ongoing Exploration: As required
Early Exploration: 1972
Rate:
Possible Production Date:

Geology & Coal Seams:

Seam Names	Thickness	Depth	Tonnage
	0.3 to 2.0m	< 20'	181.0×10^6 tonnes

Reserves:

	Tonnage Raw Coal	Mining Ratio (bcm/trc)
Committed:	Nil	
Proven:		
Probable:	71×10^6 tonnes	7.2
Possible:	110×10^6 tonnes	9.4
		8.6

ROM Coal Quality:

H_2O:	25.3	**Heat Content:**	4800 KCal/Kg
Ash:	7.1	**Sulphur:**	0.3
VM:	28.6	**Size Consist:**	50 mm x 0
FVC:	39.0		

Access to Transport Infrastructure: NAR railway line runs through coal field. Siding at Morinville

COAL DATA SHEET I
Reserves & Quality

Company: Luscar Ltd. Phone: (403) 420-5810

Contact: R. Engler

Coal Property: Barrhead

Field: Barrhead

Location: Two areas; one 8 miles north of Barrhead Townsite and the other 5 miles to the southeast along the Pembina River.

Property Status: Inactive

Production: Not Scheduled
Development: Not Scheduled
Completed Feasibility: No
Ongoing Exploration: Drilling on North Block Scheduled for 1985
Early Exploration: 1975, 135 drill holes
Rate: 1 million tons/year
Possible Production Date: Late 1980's.

Geology & Coal Seams:

Seam Names	Thickness	Depth	Tonnage
Clover Bar Seam	3.5 ft. to 7.5 ft.	120 ft. (max.)	40 million

Reserves:

	Tonnage Raw Coal	Mining Ratio (bcm/trc)
Committed: N/A		
Proven:	40 million	11:1
Probable: N/A		
Possible: N/A		

ROM Coal Quality: Subbituminous C

H_2O:	25.5%	Heat Content:	7821 Btu/lb
Ash:	11.44%	Sulphur:	0.5 maximum
VM:	29.0%	Size Consist:	
FC:	34.0%		

Access to Transport Infrastructure: The deposits are centered around the town of Barrhead. The Northern Alberta Railway runs through both mining blocks.

COAL DATA SHEET I
Reserves & Quality

Company: Luscar Ltd. Phone: (403) 420-5810

Contact: R. Engler

Coal Property: Slave Lake

Field: Lesser Slave Lake

Location: 135 miles northwest of Edmonton. 26,600 acres of Crown Coal Leases extending along the south shore of Lesser Slave Lake

Property Status: Inactive

Production: Not scheduled
Development: Inactive
Completed Feasibility: 1978 Mining Feasibility Study
Ongoing Exploration: Infill drilling required
Early Exploration: 1971 to 1975, 303 drill holes
Rate: Possible 2 million tonnes per year
Possible Production Date: Early 1990's

Geology & Coal Seams:

Seam Names	Thickness	Depth	Tonnage

9 coal seams have been identified over a 400 foot stratigraphic interval ranging in thickness from 7 feet to less than 2 feet. Three to four of these seams are mineable with each of the four separate blocks that form the property to a maximum depth of 120 feet.

Reserves:	Tonnage Raw Coal	Mining Ratio (bcm/trc)
Committed: N/A		
Proven:	120 million	14.4:1
Probable: N/A		
Possible: N/A		

ROM Coal Quality: Lignite A

H_2O:	31.0%-35.2%	Heat Content:	7020 - 7870 Btu/lb
Ash:	3.5%- 6.5%	Sulphur:	N/A
VM:	27.0%-27.8%	Size Consist:	N/A
FC:	31.0%-37.7%		

Access to Transport Infrastructure: Central mining block is 4 miles south of Slave Lake Townsite. The Northern Alberta Railway parallels the property.

COAL DATA SHEET I
Reserves & Quality

Company: Luscar Ltd. Phone: (403) 420-5810

Contact: R. Engler

Coal Property: Tofield

Field: Tofield/Dodds

Location: Luscar leases extend from the town of Tofield southward for 11 miles.

Property Status: Inactive

Production: Not Scheduled
Development: Inactive
Completed Feasibility: 1982 and 1984 mine feasibility studies
Ongoing Exploration: 1982: 268 drill holes and core holes
Early Exploration: 1977: 122 drill holes and 28 core holes
Rate: Possible 2 million tons per year
Possible Production Date: Late 1980's

Geology & Coal Seams:

Seam Names	Thickness	Depth	Tonnage
Dodds Seam	4.0 ft.-8.0 ft.	100 ft. (Max.)	114 Million RST

Reserves:

		Tonnage Raw Coal	Mining Ratio (bcm/trc)
Committed:	N/A		
Proven:		114 M RST	8:1
Probable:	N/A		
Possible:	N/A		

ROM Coal Quality: Subbituminous C

H_2O:	25.0%	Heat Content:	8000 Btu/lb
Ash:	11.0%	Sulphur:	0.50%
VM:	29.6%	Size Consist:	
F C:	34.4%		

Access to Transport Infrastructure: The main coal deposit is within 1 mile of the Tofield townsite. The area is proximal to the C.N.R. Mainline.

COAL DATA SHEET I
Reserves & Quality

Company: Luscar Ltd. Phone: (403) 420-5810

Contact: R. Engler

Coal Property: Halkirk

Field: Battle River

Location: Extending directly south of FCL Paintearth Mine to the town of Halkirk.

Property Status: Inactive

Production: Not Scheduled
Development: Not Scheduled
Completed Feasibility: None undertaken
Ongoing Exploration: Coring requested for coal quality
Early Exploration: 1970 - 1975
Rate: 2 million tons/year
Possible Production Date: Early 1990's.

Geology & Coal Seams:

Seam Names	Thickness	Depth	Tonnage
Paintearth	2 to 10 ft.	20 ft. - 100 ft.	N/A
Battle River	2 to 6 ft.	65 ft. - 120 ft.	N/A

Reserves:

	Tonnage Raw Coal	Mining Ratio (bcm/trc)
Committed:	0	
Proven:	81.5 million	10.3:1
Probable:	81.2 million	10.8:1
Possible: N/A		

ROM Coal Quality: Subbituminous C

H_2O:	25%	Heat Content:	7800 Btu/lb
Ash:	11%	Sulphur:	0.5%
VM:	29%	Size Consist:	
FC:	35%		

Access to Transport Infrastructure: The CPR line extending from Red Deer is within 6 miles of the Halkirk mining area.

COAL DATA SHEET I
Reserves & Quality

Company: Luscar Ltd. Phone: (403) 420-5810

Contact: R. Engler

Coal Property: Castor

Field: Battle River

Location: 30 miles east of Stettler and directly southwest of the town of Castor.

Property Status: Inactive

Production: Not Scheduled
Development: Not Scheduled
Completed Feasibility: Preliminary Mining Study
Ongoing Exploration: Required for coal quality
Early Exploration: 1970 - 1975: 1050 drill holes
Rate: 2 to 4 million tons/year
Possible Production Date: Early 1990's

Geology & Coal Seams:

Seam Names	Thickness	Depth	Tonnage
Upper	2 ft. to 5 ft.	.45 ft.	N/A
Lower	.5 ft. to 6.5 ft.	25 ft. to 110 ft.	N/A

Reserves:

	Tonnage Raw Coal	Mining Ratio (bcm/trc)
Committed:	0	0
Proven:	298 Million	9.5:1
Probable:	N/A	N/A
Possible:	N/A	N/A

ROM Coal Quality: Subbituminous C

H_2O:	25%	Heat Content:	7800 Btu/lb
Ash:	11%	Sulphur:	0.5%
VM:	29%	Size Consist:	
FC:	35%		

Access to Transport Infrastructure: The CPR line running from Red Deer crosses through the mine block at Castor.

TransAlta Utilities

MEMORANDUM

DRAFT

III-16

FROM D. Nikols - T1-403

May 1, 1985.

TO P.C. Roxburgh - T1-403

SUBJECT ISLE LAKE AT 1.5 X 10^6 TONNES/YEAR

Property Name: Isle Lake Northwest Zone Pits 1 & 2

Production Rate: 1.5 x 10^6 tonnes/year

Basic Assumption: The average stripping ratio 6.35 bcm/t = 9.5 x 10^6 bcm/year. 1985 dollars.

1.	Operating cost:	
	Including stripping maintenance, engineering, coal loadout and reclamation.	$6.2387/t
2.	Capital cost:	
	All investment for mining related work, equipment, infrastructure, reclamation and so on.	$1.4735/t
3.	Crown Royalty X 2	$ .7712/t
	Sub-total Operating and Capital for Mining Coal	$8.4893/t
4.	Additional Cost:	
	Transportation Infrastructure Land Acquisition Pre-production Operating Haul Road and Catchment Construction Power Distribution Existing Facility Relocation Working Capital	
	Assume 15% of Total Capital Budget	$ .221/t
5.	Grand Total	$8.7043/t

mh:D5/3/29

TransAlta Utilities

MEMORANDUM

III-17

DRAFT

FROM D. Nikols - T1-403

April 30, 1985.

TO P.C. Roxburgh - T1-403

SUBJECT ISLE LAKE AT 1 X 10^6 TONNES/YEAR

Property Name: Isle Lake Northwest Block Pits 1 & 2

Production Rate: 1 x 10^6 tonnes/year

Basic Assumption: The average stripping ratio 4.77 bcm/t = 4.77 x 10^6 bcm/year. January 1985 dollars.

1.	Operating cost:	
	Including stripping maintenance, engineering, coal loadout and reclamation.	$6.2387/t
2.	Capital cost:	
	All investment for mining related work, equipment, infrastructure, reclamation and so on.	$1.764/t
3.	Crown Royalty	$ .80/t
	Sub-total Operating and Capital for Mining Coal	$8.8029/t
4.	Additional Cost:	
	Transportation Infrastructure **Land Acquisition** **Pre-production Operating** **Haul Road and Catchment Construction** **Power Distribution** **Existing Facility Relocation** **Working Capital**	
	Assume 15% of Total Capital Budget	$ .2646/t
5.	Grand Total	$9.0675/t

mln:D5/5/2E

TransAlta Utilities

MEMORANDUM

III-18

DRAFT

FROM D. Nikols - T1-403

April 30, 1985.

TO P.C. Roxburgh - T1-403

SUBJECT ISLE LAKE AT .5 X 10^6 TONNES/YEAR

Property Name: Isle Lake Northwest Zone Pit 2

Production Rate: .5 x 10^6 tonnes/year

Basic Assumption: The average stripping ratio 3.66 bcm/t = 1.8 x 10^6 bcm/year. 1985 dollars.

1.	Operating cost:	
	Including stripping maintenance, engineering, coal loadout and reclamation.	$6.2387/t
2.	Capital cost:	
	All investment for mining related work, equipment, infrastructure, reclamation and so on.	$2.0587/t
3.	Crown Royalty X 2	$ .8297/t
	Sub-total Operating and Capital for Mining Coal	$9.0743/t
4.	**Additional Cost:**	
	Transportation Infrastructure **Land Acquisition** **Pre-production Operating** **Haul Road and Catchment Construction** **Power Distribution** **Existing Facility Relocation** **Working Capital**	
	Assume 15% of Total Capital Budget	$ .3088/t
5.	Grand Total	$9.3831/t

ml.:D5/5/23

FORM NO. 308-0043 8

APPENDIX IV

ALBERTA PLAINS SURFACE THERMAL COAL

MINE COST DATA

IV.1 Operating Costs
IV.2 Capital Costs

CAPITAL EQUIPMENT SCHEDULE 3000000 TONNES/YEAR STRIP MINE, ALBERTA

PREPRODUCTION CAPITAL TOTAL MILLIONS $ 67.70
REPLACEMENT CAPITAL MILLIONS $ 66.70

MAJOR EQUIPMENT	UNIT COST	YEARS -5	-4	-3	-2	-1	1	2	3	4	5	6	7	8	9	10	11	12	13	14	15	16	17	18	19	20	21	22	23
DRAGLINE-25c	23,400,000	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0
DRAGLINE-34c	30,000,000	0	0	0	0	30,000,000	0	0	0	0	0	0	0	0	0	0	0	9,000,000	0	0	0	0	0	0	0	0	0	0	0
DRAGLINE-42c	35,000,000	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0
DRAGLINE-56c	46,000,000	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0
SCRAPERS	800,000	0	0	0	1,600,000	3,200,000	0	0	0	0	4,000,000	0	0	0	0	0	0	4,800,000	0	0	0	0	0	0	0	0	0	0	0
ELECTRIC SHOVEL 14c	2,000,000	0	0	0	0	2,000,000	0	0	0	0	0	0	0	0	0	0	0	960,000	0	0	0	0	0	0	0	0	0	0	0
HYDRAULIC SHOVEL-14c	2,400,000	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0
COAL HAULER	750,000	0	0	0	0	1,000,000	0	0	0	0	2,000,000	0	0	0	0	3,000,000	0	0	0	0	1,000,000	0	0	0	0	2,000,000	0	0	0
TRUCKS-150T	975,000	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0
TRUCKS-777	835,000	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0
CONVEYOR-1c		0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0
HEAD STATIONS		0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0
TAIL STATIONS		0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0
DRIVES		0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0
FEEDER BREAKER		0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0
F.E.LOADER-5C	465,000	0	0	0	0	465,000	0	0	0	0	465,000	0	0	0	0	465,000	0	0	0	0	465,000	0	0	0	0	465,000	0	0	0
F.E.LOADER-10C	900,000	0	0	0	0	900,000	0	0	0	0	0	0	900,000	0	0	0	0	0	0	900,000	0	0	0	0	0	0	900,000	0	0
F.E.LOADER-CUR	450,000	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0
DOZER-D9	425,000	0	0	0	0	425,000	0	0	0	0	0	0	0	0	0	425,000	0	0	0	0	0	0	0	0	0	425,000	0	0	0
GRADALL-100	265,000	0	0	0	0	265,000	0	0	0	0	0	0	0	0	0	265,000	0	0	0	0	0	0	0	0	0	265,000	0	0	0
DOZER/RIPPER-340CH	680,000	0	0	0	0	2,400,000	0	0	0	0	2,400,000	0	0	0	0	2,400,000	0	0	0	0	2,400,000	0	0	0	0	2,400,000	0	0	0
DOZER/RIPPER-300CH	580,000	0	0	0	1,000,000	0	0	0	0	0	1,000,000	0	0	0	0	1,000,000	0	0	0	0	1,000,000	0	0	0	0	1,000,000	0	0	0
DOZER/WINCH-340CH	250,000	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0
GRADER-1980	416,000	0	0	0	416,000	0	0	0	0	0	0	0	0	0	0	416,000	0	0	0	0	0	0	0	0	0	0	0	0	0
COMPACTOR	374,000	0	0	0	374,000	0	0	0	0	0	0	0	0	0	0	0	0	374,000	0	0	0	0	0	0	0	0	0	0	0
WATER/SANDER	880,000	0	0	0	0	880,000	0	0	0	0	0	880,000	0	0	0	0	0	0	0	880,000	0	0	0	0	0	0	880,000	0	0
CRANE-90T	880,000	0	0	0	0	880,000	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0
CRANE-30T	300,000	0	0	0	0	300,000	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0
LO-BED HAULER	175,000	0	0	0	0	175,000	0	0	0	0	0	0	0	0	0	175,000	0	0	0	0	0	0	0	0	0	175,000	0	0	0
FLAT DECK TRUCK	250,000	0	0	0	0	250,000	0	0	0	0	0	0	0	0	0	250,000	0	0	0	0	0	0	0	0	0	0	0	0	0
LIGHT PLANTS	50,000	0	0	0	0	250,000	0	0	0	0	250,000	0	0	0	0	250,000	0	0	0	0	250,000	0	0	0	0	250,000	0	0	0
MECH SERVICE TRUCKS	492,000	0	0	0	492,000	984,000	0	0	0	1,476,000	0	0	1,476,000	0	0	0	0	1,476,000	0	0	0	1,476,000	0	0	0	1,476,000	0	0	0
DESIGN/AMBULANCE	37,000	0	0	0	37,000	0	0	0	0	0	0	0	0	0	0	0	0	37,000	0	0	0	0	0	0	0	0	0	0	0
PICKUPS	16,300	0	0	0	32,600	130,400	32,600	32,600	32,600	32,600	32,600	32,600	32,600	32,600	32,600	32,600	32,600	32,600	32,600	32,600	32,600	32,600	32,600	32,600	32,600	32,600	32,600	32,600	16,300
WATER WELL	270,000	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0
CREW BUS	80,000	0	0	0	0	80,000	0	0	0	0	80,000	0	0	0	0	80,000	0	0	0	0	0	80,000	0	0	0	0	80,000	0	0

BUILDINGS & SITE SERVICES

MINE SERVICE GARAGE	5,000,000	0	0	0	2,500,000	2,500,000	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0
AUTOMOTIVE SHOP	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0
FUEL & LUBE FACILITY	425,000	0	0	0	0	425,000	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0
WAREHOUSE YARD	490,000	0	0	0	245,000	245,000	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0
PARKING	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0
EXPLOSIVES MAGAZINE	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0
MINE DEWATERING	750,000	0	0	0	375,000	375,000	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0
ELECTRICAL DISTRIBNT	2,000,000	0	0	0	0	2,000,000	0	0	0	0	400,000	0	0	0	0	400,000	0	0	0	0	400,000	0	0	0	0	400,000	0	0	0
UTILITIES	1,500,000	0	0	0	750,000	750,000	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0
PREPRODUCTION WORK	6,000,000	0	1,500,000	1,500,000	3,000,000	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0
LOADOUT FACILITY	2,500,000	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00
TOTAL CAPITAL COST		0	1,500,000	1,500,000	10,871,600	22,519,000	32,600	32,600	32,600	1,508,600	12,627,600	32,600	1,732,600	1,508,600	32,600	9,208,600	32,600	16,619,600	32,600	1,732,600	7,747,600	1,508,600	32,600	32,600	32,600	10,008,600	1,012,600	32,600	16,300

APPENDIX V

V.1 Thermotics Canada 190 GJ/hr
Gas Fired Generators V-2

V.2 Babcock & Wilcox -
Budget Estimate for PCF
Generators V-9

ITEM III

3.0 180mm BTU/HR. GAS FIRED STEAM GENERATOR

MODEL:	SG-180-NGS-25
OUTPUT:	180mm Btu/hr. at 80% quality steam
DISCHARGE PRESSURE:	2500 psig
FEEDWATER FLOWRATE:	182,500 lbs/hr. @ 95^{o}C feedwater temperature
THERMAL EFFICIENCY:	81.83% based on gross heating value at 15% excess air and 390^{o}F stack temperature.

3.1 General Description

The unit is a once-through, three parallel pass (1:2:3:3:2:1 arrangement), direct fired steam generator consisting of a combustion-radiant section, convective section, burner, complete with all safety equipment required for safe and efficient operation. The unit contains all valving, interconnecting piping, instrumentation, and equipment.

The unit is constructed on a structural steel skid with controls, monitors, process connections and wiring to termination boxes located at the edge of the generator skid.

3.2 Codes

Unit to be designed and fabricated in accordance with the ASME Power Boiler Code, Section 1 and CSA Electrical Code. Unit to be approved by the Alberta Boiler Branch and Electrical Protection Branch.

3.3 Radiant Section and Combustion Chamber

The radiant heat transfer section of the generator will be horizontal, three pass, straight tube design with these tubes transposed around the inner diameter of a refratory-lined cylindrical combustion chamber. Tube location and spacing and the dimensions of the combustion chamber are sized for an average radiant heat transfer of 15,000 BTU/FT^{2}/HR. Tubes to be 3" Sch. 160, SA-53 Gr. B or equivalent.

The tubes are supported by "full circle", 25% chrome/ 12% nickel alloy hanger castings.

Two air-cleaned view windows shall be incorporated into radiant section to observe combustion.

All return bends shall be inside the combustion chamber.

A panel mounted gauge monitoring furnace combustion pressure is provided.

3.4 Convective Section

The convective heat transfer section of the generator is a three pass tube bundle of vertical design with refractory-lined tube sheets and side panels. The convective tube bundle dimensions and fin arrangements are designed to optimize gas mass flows with minimum gas side pressure drop to obtain high heat transfer coefficients. The four lower or gas inlet side tube rows are bare shock tubes. The upper rows of tubes are extended surface tubes with all fins wrapped and continuously welded in tension.

All fins to be of the solid type, Kentube or equal.

Tubes to be 3" Sch. 160, SA-53 Gr. B or equal.

Tubes are arranged in tube sheets to allow removal of individual convective tubes. Side walls are desiged with 1/4" maximum fin clearance to prevent flue gases from bypassing the tube bundle.

The inlet and outlet piping is equipped with flanges or Grayloc hubs for quick assembly and disassembly.

The support structure is refractory-lined and contoured to prevent water and sludge from entering the radiant section during washing operations.

The support structure is equipped with a quick release, light-weight entrance manway. The manway is refractory-lined and equipped with davit.

A rear-mounted, air-cooled view window will be provided for inspection of flame pattern and convective section tubes.

A ground level flue gas sampling tube is provided.

3.5 Refractory System

Unit to have a ceramic fibre-lined combustion chamber with radiant heat tube transposed around the chamber. The refractory system in this chamber is designed for maximum insulation to meet outside casing temperature of 80°C based on 15.6°C ambient temperature and 5 ft/second air velocity.

3.6 Burner

Unit to be equipped with a North American Model 4150-2000-C gas fired burner with floor mounted forced draft turbo blower complete with the following accessories:

1. Three phase, 60 Hertz, 150 HP TEFC, 1800 RPM motor.
2. Heavy duty pilot system complete with spark electrode, solenoid valve, reducing regulator. Manifold to skid edge for natural gas.

The burner is mounted in the centre of the fire wall to eliminate flame impingement on tubes, supports and refractory. All valves and controls are located for easy accessibility. Firing rate is controlled by pneumatic powered unit and synchronized with feedwater flow rate.

3.7 Gas Train

Main Gas Cock	--- Plug Valve
Safety Shut Off Valve	--- (2) Honeywell or Equal
Gas Vent Valve	--- 3/4" Asco (N.O.)
Regulator	--- Fisher 1098 EGR or Equal
Flow Orifice Union	--- Daniel

Gas train to terminate at edge of skid with a butt weld connection.
Gas pressure at Generator skid: 75 psig (138 kPa) max.

3.8 Feedwater System

The generator feedwater system consists of the following major components:

3.8.1 Feedwater Check Valve

Manufacturer	- Edwards
Size	- 4"

3.8.2 Feedwater Stop Valve

Manufacturer	- Edwards
Size	- 4"

3.8.3 Flow Control Valves

Manufacturer	- Fisher
Size	- 3" - 1500# flanged (RFWN)
Quantity	- One per pass

3.8.4 Flow Nozzle

Manufacturer	- Daniel
Size	- 3" - 1500# RFWN
Quantity	- One per pass

All feedwater piping is contained within the skid and terminates at edge of skid with a butt weld connection.

3.9 Control Equipment

Not included.

3.10 Gauges, Thermometers

The generator is equipped with all necessary pressure gauges and thermometers to monitor generator operation. All equipment is located for easy, ground level reading.

3.11 Air Compressors

Instrument Air - to be supplied by Customer

3.12 Steam Discharge Piping

The steam discharge piping shall be contained within the skid and manifolded into a single outlet butt weld connection. Discharge piping shall include the following:

3.12.1 Safety Valves - (4)

As required per the ASME Code.

Manufacturer	- Crosby or Consolidated
Size	- 2" x 3" - 1500/300 lb. Flanged

3.12.2 One steam quality sample separator on each pass (3).

3.12.3 Steam Discharge Stop Valves - (2)

Manufacturer	- Edwards or equal
Size	- 6"

3.12.4 Steam Discharge Check Valve - (1)

Manufacturer	- Edwards or equal
Size	- 6"

3.13 A convective flue gas transition and short stack with a butterfly damper valve is included. The stack and damper shall be designed to withstand the weight of a 60" Corten stack (not included) to a height of 60 ft.

3.14 Painting

All surfaces above 150°F are to have one (1) coat of high temperature aluminum paint. Other parts to have one (1) coat of zinc primer and one (1) coat of high temperature enamel.

3.15 X-ray 10% of the quantity of welded joints of pressure pipes in the radiant, convective sections and external high pressure piping is included.

3.16 All piping to and from the generator such as gas supply, feedwater inlet, steam line, drain will be prepiped, with buttweld connections at edge of skid.

BUDGET ESTIMATE PRICE, F.O.B. EDMONTON, ALBERTA. . . . $900,000.00
CANADIAN DOLLARS

DELIVERY: Thirty-four (34) to thirty-six (36) weeks.

ITEM II

2.0 Feedwater Plunger Pump & Accessories

2.1 Pump

Manufacturer - Wheatley
Model No. - HP-250M
Size - 2 1/4" x 3"

BUDGET ESTIMATE PRICE. $47,300.00

2.2 Motor

Manufacturer - Toshiba
HP - 200
RPM - 1200

BUDGET ESTIMATE PRICE. $11,500.00

2.3 Accessories

Belts - Epton
Sheaves - Browning
Beltguard - Thermotics

BUDGET ESTIMATE PRICE. . . . . .$ 4,500.00

2.4 Feedwater Pump Suction Stabilizer

Manufacturer - Pulsation Engineering
Size - 4"

BUDGET ESTIMATE PRICE. . . . . $ 1,800.00

2.5 Feedwater Pump Discharge Pulsation Dampener

Manufacturer - Fluid Kinetics
Size - 2 1/2" x 3"

BUDGET ESTIMATE PRICE. . . . . $ 3,200.00

2.6 Air Compressor

Manufacturer - Quincy
Size - 10 scfm @ 100 psig

BUDGET ESTIMATE PRICE. . . . . $ 3,500.00

APPENDIX V.2

Babcock & Wilcox Canada

Babcock & Wilcox Industries Ltd. a McDermott company

Suite 605, Gulf Canada Square
401-9th Avenue S.W.
Calgary, Alberta T2P 3C5
(403) 263-5964
Telex: 038-21887

May 22, 1985

L. A. Smith Consulting & Development Ltd.
201 - 701 - 14th Street N.W.,
Calgary, Alberta.
T2N 2A4

Attention: Mr. L. A. Smith

Re: Budget Estimate for Pulverized Coal Fired Generators. Our Ref. W-8968

Gentlemen:

In answer to your letter of April 26th, 1985, and confirming a telephone conversation between the writer and your Mr. Eric Allen of today, we are pleased to quote, herewith, the following estimating prices:

A. One (1) 500 X 10:6 BTU/hr., 2250 psig, 855 Degrees F., Steam Generator

Estimated Price: Twenty Million, Two Hundred and Fifty Thousand Dollars... ($20,250,000.) today's cost, delivered and erected in Alberta.

B. One (1) 350 X 10:6 BTU/hr., 2250 psig, 855 Degrees F., Steam Generator.

Estimated Price: Seventeen Million, Two Hundred and Fifty Thousand Dollars... ($17,250,000.) today's cost, delivered and erected in Alberta.

Scope of Supply: (Each Alternate)

Boiler with Mountings
Superheater with Mountings
Economizer with Mountings
One MPS Pulverizer
Coal Feeders
Six Coal Burners with Gas Ignitors
Sootblowers with Piping, Valves and Fittings
Flues and Ducts
Thermoprobe
Thermocouples
Electrostatic Precipitator

Babcock & Wilcox Canada

May 22, 1985

I.D. Fan and Drive
F.D. Fan and Drive
P.A. Fan and Drive
Sealing Air Fan and Drive
Combustion Control System
Flame Failure Safeguard System
Regenerative Air Heater
Ash Handling System (Bottom Ash only)
Deaerator
Boiler Feed Water Pumps
Insulation and Lagging
Boiler Steel
Transportation to Alberta
Unloading and Erection

The foregoing prices are estimating prices only and are not given by Babcock & Wilcox Canada as an offer, nor as a term of any contract.

Should you require further information, or clarification, please do not hesitate to contact us.

Yours very truly,
BABCOCK & WILCOX CANADA

P. W. Heighton
Manager, Western Branch

PWH*wb

APPENDIX VI

VI.1 Special Report, Power, 1985..... VI-1

VI.2 C.E. NATCO - Fluidized Bed Combustion System VI-13

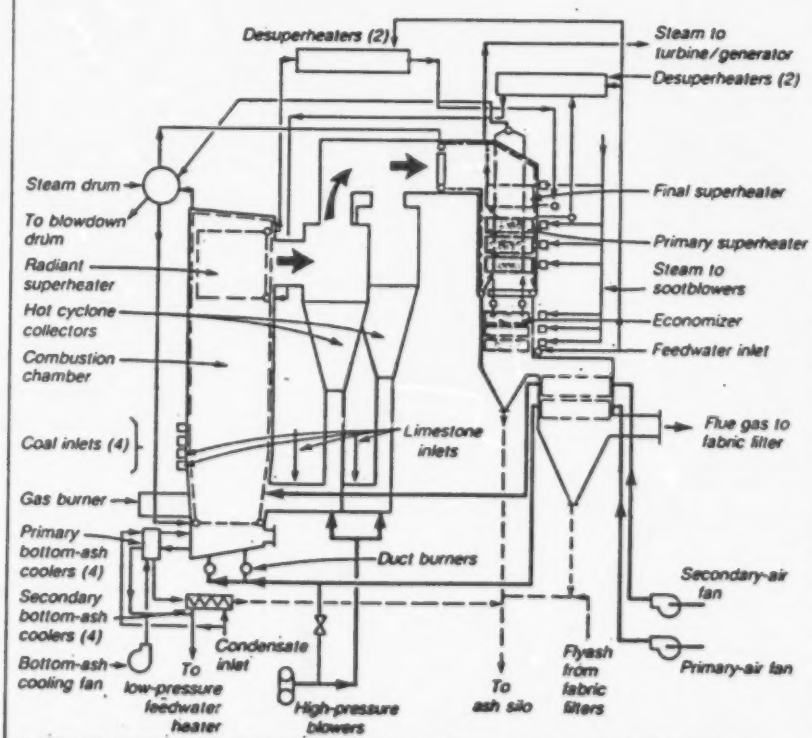
VI.3 Pyropower Corp - Operating Experience, California's First Coal Fired Steam Generator..... VI-17

Special Report

Fluidized-bed boilers achieve commercial status worldwide

US electric utilities give atmospheric fluidized-bed technology their blessing by investing in three demonstration projects employing the world's largest such boilers. Confident industrials are ordering units for process-steam and cogeneration service, several with ratings above 200,000 lb/hr on difficult fuels

By Bob Schwieger, Editor-in-Chief



1. First fluidized-bed boiler built for central-station service, rated 925,000 lb/hr at 1510 psig/1005F, will be installed by Colorado-Ute Electric Assn Inc

Atmospheric fluidized-bed (AFB) technology for steam and electric generation got a big boost last year when three electric utilities—Colorado-Ute Electric Assn Inc, Northern States Power Co, and Tennessee Valley Authority—and their partners committed more than $300-million to the construction of three demonstration plants, ranging in size from 100 to 160 MW. The vote of confidence by US utilities, traditionally among the most demanding companies when it comes to adopting new technology, means to many industry observers that AFB boilers are truly commercial.

Perhaps the most surprising aspect of the rapid commercialization of the fluidized-bed boiler—the first successful coal-fired watertube unit, a bubbling-bed steam generator, began operation at Georgetown University only six years ago—is industry's fascination with circulating fluidized-bed (CFB) systems.

Though only two CFBs are now operational in this country—at Gulf Oil Exploration & Production Co, Bakersfield, Calif, and Conoco Inc, Uvalde, Tex, each rated 50,000 lb/hr—and their service time is somewhat lacking because of cutbacks in oil-field production, US companies recently have ordered at least eight such boilers rated more than 400,000 lb/hr each and several others capable of producing more than 100,000 lb/hr (see tables, pp S-6, S-10, and S-14). When one considers that CFBs operating overseas (the largest is 270,000 lb/hr) have relatively little experience burning coal, the primary fuel here, the investment in them appears even more surprising to some industrial sources.

However, the general consensus among knowledgeable engineers is that CFBs certainly are worthy of the attention they're getting. These boilers typically operate at higher combustion efficiencies and at lower excess-air levels than the more familiar bubbling-bed steam generators (POWER special report, *Fluidized-bed boilers*, August 1982). CFBs also have more forgiving fuel-feed systems, typically require less limestone for SO_2 capture, and usually are more easily adaptable to staged-combustion techniques for NO_x control than bubbling beds.

US interest in the CFB, nurtured primarily by Pyropower Corp, probably was not anticipated by the traditional boiler manufacturers. Babcock & Wilcox Co, Combustion Engineering Inc, and Riley Stoker Corp each now offer CFB boilers under license or in cooperation with overseas manufacturers (see table, pp S-2 and S-4). And even though Keel-

List of manufacturers offering AFB

COMPANY ADDRESS	CONTACT TITLE	TELEPHONE[1] TELEX	Are AFB boilers built under license?	Company technology licensed from	Affiliated with another company offering AFB boilers?	Company affiliated with	Type of affiliation	Type(s) of AFB boiler(s) offered	Type(s) of fluidized bed combustion system(s) offered	BOILER CAPABILITIES: Capacity, 1000 lb/hr	BOILER CAPABILITIES: Pressure, psig	BOILER CAPABILITIES: Temperature, F	BOILER CAPABILITIES: Fuel(s)
A Ahlström Oy Varkaus Boiler Works SF-78201 Varkaus 20, Finland	Leif Bengtsson Marketing Manager	358-77-211 4319 ALMEK SF	No	—	Yes	—[20]	—[20]	Wt	Cr	30 to 1000	Up to 2500	Up to 1005	—[3]
Ansaldo SpA[20] Viale Sarca, 336 Milan 20126, Italy	Mkr	39-2-699-7208 331280	No	—	No	—	—	Wt	Bb	Up to 400	Mkr	Up to 1000	C,Ww
Babcock & Wilcox Co 20 S Van Buren Ave Barberton, Ohio 44203	Manager, Marketing Advanced Energy Systems	1-216-860-2721 98-6406 BAHOH	Yes[7]	STU	No	—	—	Wt	Bb, Cr	50 to 1500	125 to 2400	Sat to 1000	—[3]
Babcock Engrg Contractors Ltd[20] 87 Rissik St Johannesburg 2001, South Africa	J K Pollock Sales Manager	27-11-833-4311 80806	Yes	BPL	No	—	—	Wt	Bb	10 to 100	Up to 500	Up to 900	—[3]
Babcock Hitachi KK 6-2, 2-chome, Oto-machi Chiyoda-ku, Tokyo 100, Japan	S Kawada, Deputy Manager, Industrial Machy & Eqt Sales Div	81-3-270-7351 222-3502	No	—	No	—	—	Wt	Bb	More than 10	100 to 2400	Up to 1050	—[3]
Babcock Power Ltd[8] 165 Great Dover St London SE1 4YB, UK	Terry Cruickshank Sales Manager	44-1-407-8383 884151/2/3 BABLON G	Yes[7]	SCS	Yes	MFP	—[5]	Wt, Fl, F/W	Bb, Cr	—[6]	More than 150	—[7]	—[3]
Babcock Worsley Ltd Liverpool Rd St. Helens WA1, UK	Ivan Hodgson Sales Manager	44-744-612111 627531 WCALTD G	No	—	Yes	BPL	Min	Fl	Bb	6 to 25	150 to 250	—[3]	—[3]
C-E Natco[20] 5330 E 31st St Tulsa, Okla 74135	Dr Suresh Sharma Project Manager	1-918-663-9100 49-2427	No	—	Yes	CEP	Sis	Wt	Bb	50 to 100	Up to 2500	Up to 670	C, Pet
C-E Power Systems[12] 1000 Prospect Hill Rd Windsor, Ct 06095	Lewis A Capuano Product Manager	1-203-285-9373 99297	No	—	Yes	LUR	—[13]	Wt	Bb, Cr	50 to 1000	100 to 1880	330 to 950	—[3]
Combustion Power Co 1346 Willow Rd Menlo Park, Calif 94025	Michael O'Hagan Director, Sales and Marketing	1-415-324-4744 843471	No	—	No	—	—	Wt	Bb[14]	15 to 250	40 to 1850	250 to 1100	—[3]
Combustion Systems Ltd Coal Research Establishment Stoke Orchard Cheltenham, Glos, GL52 4RZ, UK	P Mills General Manager	44-24-267-4339 43568 CRCRE G	—[11]	—[11]	—[11]	—[10]	—[10]	—[11]	—[11]	—[11]	—[11]	—[11]	—[11]
Danks of Netherton Ltd[20] Halesowen Rd Netherton, Dudley West Midlands DY2 9PC, UK	R Allsop Sales Manager	44-384-66417 338922	Yes	CSL	No	—	—	Wt, Fl	Bb	15 to 70	100 to 900	Up to 900	—[3]
Dedert Corp Thermal Processes Div 20000 Governors Dr Olympia Fields, Ill 60461	J L Burghard President	1-312-747-7000 25-3889	No	—	Yes	—[9]	—[9]	Wt, Fl	Bb	5 to 100	10 to 900	Sat to 825	—[3]
DeRak Corp 13330 12th Ave North Plymouth, Minn 54440	Michael Carroll Sales Manager	1-612-544-3371 29-0812	No	—	No	—	—	Wt	Bb	40 to 80	Up to 900	Up to 900	—[3]

MANUFACTURERS
- AHL -A Ahlström Oy (Finland)
- BPL -Babcock Power Ltd (UK)
- BDC -Battelle Development Corp
- BW -Babcock & Wilcox Co
- CEP -Combustion Engineering Inc, Power Systems
- CSL -Combustion Systems Ltd (UK)
- DBW -Deutsche Babcock Werke AG (FRG)
- DFC -Fluidized Combustion Ltd, formerly Deborah Fluidized Combustion Ltd (UK)
- FCC -Fluidized Combustion Co, a joint venture of Foster Wheeler Development Corp and Pope Combustion Systems Inc
- FCL -Fluidized Combustion Contractors Ltd (UK)
- FWC -Foster Wheeler Corp
- FWL -Foster Wheeler Power Products Ltd (UK)
- GEI -Gilbertson Energy Systems Inc
- GEL -Gilbertson Energy Systems Ltd (Canada)
- IBW -International Boiler Works Co
- LUR -Lurgi GmbH (FRG)
- MFB -Multifuel Boilers Inc
- RS -Riley Stoker Corp
- SCS -Solids Circulation Systems Inc
- SFF -Stone FluidFire Ltd (UK)
- STF -Struthers Thermo-Fluid Corp
- STU -Studsvik Energiteknik AB (Sweden)
- UHL -Uhe Worcester Ltd (Japan)
- VKW -Verenigde Kesselfabrieken AG (FRG)

SYMBOLS
- Bb -Bubbling bed
- C -Coal
- Cr -Circulating bed
- Fl -Fluidized

F/W -Firetube and watertube
JV -Joint venture
Lic -License arrangement
Mkr -Not available
Pet -Petroleum coke
Sat -Saturation temperature
Sis -Sister company
Sub -Subsidiary
Wos -Wholly owned subsidiary
Wt -Watertube
Ww -Woodwaste

FOOTNOTES
1 -Includes country and city codes along with local number. When dialing overseas from the US, first dial the international access code, 011, and then the number listed in the tabulation.
2 -License is for circulating AFB systems only
3 -Designed to burn the following fuels separately or in combination: coal, woodwaste, biomass, liquid wastes or sludges, coal-washing wastes
4 -The Industrial & Marine Boiler Div has responsibility for fluidized-bed equipment within Babcock Power Ltd. The London office typically handles units larger than about 50,000 lb/hr, while the Birmingham office usually has responsibility for units that are and smaller. BPL is located at 65 Livery St, Birmingham B3 1HL, England. Contact there is Peter Harcomb, Sales Manager, telephone 44-21-236-7881, telex 337069 BABPOW G
5 -Joint venture of Babcock Power Ltd and Solids Circulation Systems Inc
6 -Will build units larger than 10,000 lb/hr to suit customer requirements
7 -Will design to suit customer requirements
8 -Company established to promote the so-called solids circulation boiler in North America

er/Dorr-Oliver Boiler Co sells CFBs of its own design, the company was not actively publicizing this aspect of its business before selling six units to Archer Daniels Midland Co for plants in Iowa and Illinois. Foster Wheeler Energy Corp also recently announced plans to offer CFBs of its design.

First utility CFB boiler

Colorado-Ute is installing the nation's first utility CFB steam generator (Fig 1) at its Nucla generating station, located in the western part of Montrose County, as part of a major life-extension project which will (1) increase plant capacity from its present 36 MW to 110 MW, for an investment of $840/kW, (2) improve net station heat rate by 15%, (3) allow a reduction in fuel cost of about 30%, and (4) reduce emissions.

Participants in the $86-million project that are sharing some of the financial risks with the utility include boilermaker Pyropower, architect/engineer Stearns Catalytic World Corp, fuel supplier Peabody Coal Corp, and turbine/generator manufacturer Westinghouse Electric Corp. The Electric Power Research Institute (EPRI) and National Rural Electric Cooperative Assn also are contributing to the project.

The upgrading effort, scheduled for completion in 1986, essentially consists of replacing three stoker-fired steam generators with one 925,000-lb/hr (at 1510 psig/1005F) CFB boiler and adding a new turbine to produce 75 MW and extraction steam to power the three existing 12-MW turbine/generators (600-psig/825F inlet conditions), which will be retained.

The utility evaluated several types of steam generators for the Nucla project, selecting the CFB unit on the basis of

A F oilers grows as early units perform well

COMPANY ADDRESS	CONTACT TITLE	TELEPHONE[1] TELEX	Are AFB boilers built under license?	Company technology licensed from	Affiliated with supplier (company offering AFB boilers)?	Company affiliated with	Type (s) of attachment	Type (s) of AFB boiler (s) offered	Type (s) of fluidized-bed combustion system (s) offered	BOILER CAPABILITIES: Capacity, 1000 lb/hr	Pressure, psig	Temperature, F	Fuel (s)
Deutsche Babcock Werke AG[20] Duisburger Strasse, 375 D-4200 Oberhausen, FRG	Dipl-Ing Hans Rocht Director	49-208-8330 856951	No	—	Yes	BBW	Sis	Wt	Bb	20 to 700	145 to 2600	—[2]	—[3]
Energie und Verfahrenstechnik GmbH Johannesstrasse, 37-45 7000 Stuttgart 1, FRG	B W Stewart Director of Licensing	49-711-669-4276 723656A EVT D	Yes[2]	AHL	No	—	—	Wt	Cr	Up to 1000	Up to 2500	Up to 1000	—[3]
Energy Equipment Co Ltd Energy House Hockliffe St Leighton Buzzard, Beds, LU7 8HE, UK	Andrew Edwards Managing Director	44-525-377600 826387	NAv	NAv	NAv	NAv	NAv	Ft	Bb	2 to 25	NAv	NAv	NAv
Energy Products of Idaho 4006 Industrial Ave Coeur d'Alene, Idaho 83814	Michael W Oswald Vice President, Sales	1-208-765-1611 152319 EPI COEU	No	—	No	—	—	Wt, Ft	Bb	10 to 250	15 to 1500	250 to 950	—[3]
Fives-Cail Babcock 7 rue Montalivet F-75383 Paris Cedex 08, France	J Y Baleito	33-1-266-3525 650-328	No	—	No	—	—	Wt	Cr[19]	60 to 1500	—[3]	Sat to 1060	—[28]
Fluidized Combustion Contractors Ltd 11 The Boulevard Crawley, Sussex RH10 1UZ, UK	C B Tydd General Manager	44-293-28755 87567	—[15]	—[15]	—[15]	—[18]	—[18]	—[18]	—[18]	—[15]	—[15]	—[15]	—[15]
Fluidized Combustion Ltd[29] Broadcasting House Newport Rd, Middlesbrough Cleveland TS1 5SA, UK	E Robinson Director	44-642-226731 58622 FLUCOM G	No	—	Yes	BW	Lic	Wt	Bb[21]	1 to 50	Up to 900	Up to 900F	—[3]
Fluidyne Engineering Corp 2900 Olson Memorial Hwy Minneapolis, Minn 55422	Erwin C Lentz Manager, Engineering Services	1-612-544-2721 290518	No	—	No	—	—	Wt	Bb	7 to 50	15 to 650	Up to 750	—[3]
Foster Wheeler Corp 110 South Orange Ave Livingston, NJ 07039	Steven E Weinberg Manager, Industrial Sales	1-201-533-2310 138568	No	—	Yes	FWL	Sub	Wt	Bb, Cr	35 to 600	150 to 2400	Sat to 1050	—[3]
Foster Wheeler Power Products Ltd Greater London House Hampstead Rd London NW1 7QX, UK	P B Chadhil Manager, Business Development	44-1-388-1212 263984	Yes	FCC, BCC	Yes	FWC	Sub	Wt	Bb, Cr	30 to 600	200 to 2000	Up to 1000	—[3]
Generator Industri AB P O Box 95 S-43322 Partille, Sweden	Roger Stroteg Export Manager	46-31-269000 21634 GENAB S	Yes[10]	FCC[10]	No	—	—	Wt, Ft, F/W	Bb, Cr	10 to 110	Up to 1160	Up to 845	—[28]
Götaverken Energy Systems AB P O Box 8734 S-40275 Göteborg, Sweden	Ronald Ingerlund Sales Manager	46-31-501000 2283 GOTAENY S	No	—	Yes	GEL GEL	Mas	Wt	Cr	50 to 500	250 to 2500	Sat to 1000	—[3]
Integral Engineering Industriebedarf GesMBH Grosse Neugasse 8 A-1041 Vienna, Austria	Filippo Rossab Managing Director	43-222-579681 112026	No	—	No	—	—	Wt	Bb	10 to 300	Up to 1200	—[3]	—[3]

9 -Typically saturated steam, though slight amounts of superheat are available
10 -A division of Combustion Engineering Inc. Focuses efforts on fluidized-bed boilers for oil-fired use
11 -Combustion Systems Ltd is an organization responsible for licensing fluidized-bed boiler technology developed by the National Coal Board and British Petroleum International Ltd; it is not a manufacturer. Licensees building steam-generating equipment include Babcock Power Ltd, M E Boilers Ltd, Danks of Netherton Ltd, Hitachi Zosen KK, Yoshimine Boiler Industry Co, Hyundai Heavy Industries Co Ltd, IAEC (Bombay) Ltd, and Stone Johnston Corp
12 -A division of Combustion Engineering Inc. Supplies fluidized-bed boilers for all markets except oil-fuld production. See listing for C-E Natco
13 -Agreement to co-market fluidized-bed boilers of the circulating bed type
14 -Bubbling-bed boilers are built under a license from Fluidized Combustion Contractors Ltd; circulating-bed boilers under a license from Battelle Development Corp
15 -Fluidized Combustion Contractors Ltd, wholly owned by Babcock Power Ltd, concentrates on fluidized-bed combustion technology development, providing a service to Babcock Power Ltd, its associated companies, and licensees. FCL no longer sells fluidized-bed boilers. That activity within the BPL organization is handled by BPL London and Birmingham and Babcock Worsley Ltd (see listings for those organizations)
16 -Purchased the Fluidized-Bed Div of Energy Resources Co. listed in Power's last survey of fluidized-bed boiler manufacturers (August 1982, p S-8)
17 -Units feature recirculation of fines at ratios as high as 15:1 (lb fines to lb fuel feed)
18 -Pyropower Corp, US, is a subsidiary; EVT Energie und Verfahrenstechnik GmbH, FRG, is a licensee; Hyundai Heavy Industries Co Ltd, Korea, Waagner-Biro AG, Austria, and Aalborg Shipyard Ltd, Denmark, are collaborating suppliers
19 -License is for bubbling-bed technology only
20 -Coal, woodwaste, biomass, and coal-washing wastes
21 -Licensees are Davison & Mason Ltd, England, Taka-Kogyo Co Ltd, Japan, and Intensa SA, Mexico
22 -Specifically, the ignited fluidized-bed combustion system
23 -In-bed circulation type
24 -Boilers can be designed for all fuels except biomass
25 -Formerly E Green & Son Ltd
26 -A subsidiary of Stone & Webster Inc
27 -Solids Circulation Systems Inc is a technology developer rather than a manufacturer of fluidized-bed boilers. Licensees of its technology are Foster Wheeler Boiler Corp, US, and Babcock Power Ltd, UK
28 -Formerly Johnston Boiler Co
29 -Induced-flow type
30 -In the US, contact W Gadsent, Manager, Solver Brothers Inc, 208 Park Ave, New York, NY 10017, Tel 1-212-949-0999, TLX 127297
31 -Licenses fluidized-bed technology to Rauma-Repola Oy Wärmo
32 -Dual-bed type
33 -Has a circulating-bed system combined with a cyclonic combustor
34 -Data not updated - since Power's last survey of fluidized-bed boiler manufacturers (August 1982, p S-8)
35 -Formerly Deborah Fluidized Combustion Ltd
36 -Units feature recirculation of fines at ratios as high as 10:1 (lb fines to lb fuel feed)
37 -Units can be designed to fire all fuels listed in footnote 3 except some liquid wastes when burned alone

cost, efficiency, and its ability to fire low-grade local fuels while satisfying stringent emissions criteria. A high-ash coal will be burned.

Nucla's new boiler will be the largest CFB steam generator in the world when it goes into service, as well as the world's largest fluidized-bed boiler of any type built new from the ground up. It works this way: High-velocity air fluidizes coal—and limestone bed material for SO_2 capture—in the combustion chamber, transporting the solids with high turbulence up the full height of the water-cooled structure. After releasing heat to the membrane waterwalls and radiant superheater, the particulate-laden combustion gases flow into the hot cyclones, as shown in the figure.

Solids, including unused limestone and unburned fuel, are returned to the combustion chamber via a nonmechanical loop seal to mix with fresh fuel and sorbent; flue gas flows through the convective heat-transfer sections, air heater, fabric filters, and out the stack. The long furnace retention time for the fuel and limestone, and the continuous circulation of them, ensure high combustion and SO_2-removal efficiencies.

The lower section of the combustion chamber includes an air-distribution grid and bottom-ash removal system. Approximately half of the heat released in the furnace at full load is transferred to the waterwalls and radiant superheater, remainder to the convective superheater, economizer, and air heater. The convective pass, typical of those in most solid-fuel-fired boilers, includes ash-removal equipment and provision for sootblowers, if required. Finally, note that primary air is supplied to the windbox below the air-distribution grid and provides the initial fluidization; addition of secondary

Major US firms extend their capabilities

COMPANY ADDRESS	CONTACT TITLE	TELEPHONE[1] TELEX	Are AFB boilers built under license?	Company technology licensed from	Affiliated with another company offering AFB boilers?	Company affiliated with	Type of affiliation	Type(s) of AFB boiler(s) offered	Type(s) of fluidized-bed combustion system(s) offered	BOILER CAPABILITIES: Capacity, 1000 lb/hr	Pressure, psig	Temperature, F	Fuel(s)
International Boiler Works Co 460 Birch St E Stroudsburg, PA 18301	Raymond B Freeman Vice President, Marketing	1-717-421-5100 510-671-4520 IBW ESTB	Yes	DFC	No	—	—	Wt	Bb[2]	5 to 75	30 to 890	Sat to 750	—[3]
Ishikawajima Harima Heavy Industries Co Ltd[4] 30-13, 5-chome, Toyo Koto-ku, Tokyo 135, Japan	H Murata Manager, Boiler Basic Design Dept	81-3-649-1111 J72232	Yes	FCC	No	—	—	Wt, Fl	Bb	—[3]	—[3]	—[3]	—[3]
Kawasaki Heavy Industries Co Ltd Sunaya 4-chome, 1-31 Konohana-ku, Osaka 554, Japan	Hiroshi Katayama Senior Manager, AFB Boiler Technology Section	81-6-461-8001 5622355 KAWAJU J	No	—	No	—	—	Wt	Bb	25 to 400	150 to 2000	360 to 1050	—[3]
Keeler/Dorr-Oliver Boiler Co 238 West St (P O Box 568) Williamsport, Pa 17703	Jurgen H Klenau Marketing Manager	1-717-327-3166 841-435	No	—	No	—	—	Wt	Bb, Cr	Up to 500	Up to 1500	Up to 1000	—[3]
Lurgi GmbH Gervinusstrasse, 17-19 D-6000 Frankfurt am Main 1, FRG	Dr L Plass Director, Engineering	49-611-1571 41236-8 LG D	No	—	Yes	CEP	—[13]	Wt	Cr	50 to 80	—[3]	—[3]	—[3]
M E Boilers Ltd M E House, Fengate Peterborough PE1 5BE, UK	W P Satchfield Director Sales and Marketing	44-733-68471 32138 MEB LTD G	Yes	CSL	No	—	—	Wt	Bb	20 to 100	Up to 2500	Up to 900	—[3]
Mitsubishi Heavy Industries Ltd 5-1, Marunouchi 2-chome Chiyoda-ku, Tokyo 100, Japan	Y Ishizuka Manager, Power Systems Overseas Operations	81-3-212-3111 J72443	No	—	No	—	—	Wt	Bb, Cr	66 to 880	920 to 1980	815 to 1000	—[3]
Mitsui Engineering & Shipbuilding Co Ltd 6-4, Tsukiji 5-chome Chuo-ku, Tokyo 104, Japan	M Okada General Manager, Boiler Plant Sales Dept	81-3-544-3306 J27871 MITZOSEN	Yes	BDC/RS	No	—	—	Wt	Cr	20 to 600	150 to 1500	Sat to 1000	—[3]
MEI Cochran Ltd[14] Newbie Works, Annan Dumfriesshire DG12 5QU, UK	A B Collins Export Manager	44-4612-2111 778183	No	—	No	—	—	Fl	Bb	2 to 36	100 to 250	Sat	—[3]
Ostohumpu Engineering Oy P O Box 27 SF-02201 Espoo 20, Finland	Tapio Laukkanen Manager, Energy Technology	358-0-4211 121853 OKJY SF	No	—	No	—	—	Fl, Wt, F/W	Bb	Up to 150	Up to 1000	Up to 950	—[3]
Power Recovery Systems Inc[15] 181 Rindge Ave Extension Cambridge, Mass 02140	Dr Robert S Dows President	1-617-576-1900 Mass	No	—	No	—	—	Wt, Fl	Bb	10 to 100	Up to 650	Up to 950	—[3]
Pyropower Corp 5120 Shoreham Place San Diego, Calif 92122	James Sahagian Director, Sales and Marketing	1-619-458-3000 506-170	No	—	Yes	AHL	Sub	Wt	Cr	50 to 1000	Up to 2500	Sat to 1005	—[3]

MANUFACTURERS
- AHL -A Ahlström Oy (Finland)
- BPL -Babcock Power Ltd (UK)
- BDC -Battelle Development Corp
- BW -Babcock & Wilcox Co
- CEP -Coalplexbau Engineering Inc, Power Systems
- CSL -Combustion Systems Ltd (UK)
- DBW -Deutsche Babcock Werke AG (FRG)
- DFC -Fluidized Combustion Ltd, formerly Deborah Fluidized Combustion Ltd (UK)
- FCC -Fluidized Combustion Co, a joint venture of Foster Wheeler Development Corp and Pope Combustion Systems Inc
- FCL -Fluidized Combustion Contractors Ltd (UK)
- FWC -Foster Wheeler Corp
- FWL -Foster Wheeler Power Products Ltd (UK)
- GEI -Gibbverken Energy Systems Inc
- GEL -Gibbverken Energy Systems Ltd (Canada)
- IBW -International Boiler Works Co
- LUR -Lurgi GmbH (FRG)
- MFB -Multifuel Boilers Inc
- RS -Riley Stoker Corp
- SCS -Solids Circulation Systems Inc
- SFF -Stone Fluidfire Ltd (UK)
- STF -Struthers Thermo-Fluid Corp
- STU -Studsvik Energiteknik AB (Sweden)
- UHL -Uhle-Wormser Ltd (Japan)
- VKW -Verenigte Kesselwerke AG (FRG)

SYMBOLS
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- C -Coal
- Cr -Circulating bed
- Fl -Fluidize
- F/W -Fluidize and watertube
- JV -Joint venture
- Lic -License arrangement
- N/A -Not available
- Pet -Petroleum coke
- Sat -Saturation temperature
- Sis -Sister company
- Sub -Subsidiary
- Wos -Wholly owned subsidiary
- WT -Watertube
- Ww -Woodwaste

FOOTNOTES
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2 -License is for circulating AFB systems only
3 -Designed to burn the following fuels separately or in combination: coal, woodwaste, biomass, liquid wastes or sludges, coal-washing wastes
4 -The Industrial & Marine Boiler Div has responsibility for fluidized-bed equipment within Babcock Power Ltd. The London office typically handles units larger than about 50,000 lb/hr, while the Birmingham office usually has responsibility for units that size and smaller. BPL is located at 55 Livery St, Birmingham B3 1HA, England. Contact there is Peter Harcomb, Sales Manager, telephone 44-21-236-7881, telex 337069 BABPOW G
5 -Joint venture of Babcock Power Ltd and Solids Circulation Systems Inc
6 -Will build units larger than 10,000 lb/hr to suit customer requirements
7 -Will design to suit customer requirements
8 -Company established to promote the so-called solids circulation boiler in North America

air in the furnace gives a staged-combustion effect, maximizing carbon burnout and minimizing NO_x production.

Fuel-feed system provides for eight hours of raw coal storage; storage capacity of crushed (1000-micron) limestone is 24 hours.

Expected stack emissions from the upgraded plant are these: 117 tons/yr of particulates, 1948 tons/yr of NO_x, and 1559 tons/yr of SO_2. The original plant emitted greater quantities of pollutants while delivering only one-third the power of the new system. Those numbers: 204 tons/yr of particulates, 911 tons/yr of NO_x, and 2826 tons/yr of SO_2 emissions.

Confidence in the CFB boiler's ability to remove SO_2 while operating efficiently comes from a wealth of test data. To illustrate: When burning ¼ in. × 0 Ohio No. 6 coal (5.14% sulfur, 13.4% ash, 12,520 Btu/lb), using 100-300-micron Lowellville limestone (93% calcium carbonate, 1.6% magnesium carbonate) as the sorbent, and operating with a 1525F combustion temperature and 8.5% excess air, SO_2 retention was 92% at a calcium-to-sulfur ratio of 1.4; combustion efficiency, 99.2%. For a low-grade Brazilian coal (1.4% sulfur, 46.9% ash), a 1580F combustion temperature, and a Ca:S ratio of 0.6, sulfur retention was 79.6% (some SO_2 being captured by the ash); combustion efficiency, 98.9%.

Largest AFB project

The fluidized-bed retrofit of the non-reheat Unit 2 boiler at Northern States Power Co's Black Dog generating plant, located only 15 miles south of downtown Minneapolis, differs from the Nucla project in several respects. The most important: An AFB combustor of the bubbling-bed type will be installed in an existing pulverized-coal-fired boiler after

...by licensing circulating-bed technology

COMPANY ADDRESS	CONTACT TITLE	TELEPHONE[9] TELEX	Any AFB boilers built under license?	Company technology licensed from	Affiliated with another company offering AFB boilers?	Company affiliated with	Type of affiliation	Type(s) of AFB boiler(s) offered	Type(s) of fluidized-bed combustion system(s) offered	BOILER CAPABILITIES: Capacity, 1000 lb/hr	Pressure, psig	Temperature, °F	Fuel(s)
Babcock Power Ltd Babcock Wilcox Ltd Boiler Div PO Box 1 Renfrew PA4 8DJ, UK	Robert A Childs Manager, Product Marketing	1-617-852-7100 920-426	Yes	FCL, BDC[10]	No	—	—	Wt	Bb, Cr	More than 40	150 to 2600	Up to 1005	—[1]
Somer Green Ltd[10] Calder Vale Rd PO Box 38 Wakefield WF1 5PF, UK	D Lloyd Crossley Boiler Sales Manager	44-924-378211 55368 EGREEN G	No	—	No	—	—	Wt	Bb	10 to 80	150 to 900	Up to 900	—[1]
Solids Circulation Systems Inc[10] 245 Summer St PO Box 2325 Boston, Mass 02107	Richard C Stone Vice President	1-617-973-2769 94-0001	—[27]	—[27]	—[27]	—[27]	—[27]	—[27]	—[27]	—[27]	—[27]	—[27]	—[27]
L&C Steinmueller GmbH Fabrikstrasse 1 D-5270 Gummersbach 1, FRG	Dr S Michelfelder Chairman	49-2261-852710 884551	No	—	No	—	—	Wt	Bb, Cr	Up to 600	Up to 2600	Up to 1000	—[1]
Stone Johnston Corp[10] 300 Pine St Ferrysburg, Mich 49409	John Wallish Product Sales Manager	1-616-842-5050 229-406	Yes	CSI	Yes	SFT	Sub	Wt,Ft	Bb[29]	2.5 to 70	Up to 700	Sat to 750	—[1]
Struthers Wells Corp 1003 Pennsylvania Ave West Warren, Pa 16365	W H Darby Director, Business Development	1-814-726-1000 91-4455	Yes	BDC	Yes	STF	Was	Wt	Cr	75 to 500	250 to 2650	Sat to 950	—[1]
Studsvik Energiteknik AB S-61182 Nyköping, Sweden	Lars Hammargren Marketing Dept	46-155-80000 64013 STUDS	No	—	Yes	BW	Lic[2]	Wt	Bb, Cr	NAv	NAv	NAv	NAv
Sulzer Brothers Ltd Zurcherstrasse CH-8401 Winterthur, Switz	W R Schmid[30] Project Engineer	41-52-813376 99686030 SZCH	No	—	No	—	—	Wt	Bb	20 to 100	150 to 1500	Up to 950	—[1]
Tampella Ltd Boiler Div P O Box 626 SF-33101 Tampere 10, Finland	Rauno P Hopia Sales Director	358-31-32400 22666 TABOI SF	No	—	Yes	—[19]	—[19]	Wt	Bb	13 to 500	Up to 1800	Up to 1000	—[1]
Voroangio Kesselwerke AG Werdener Strasse, 3 D-4000 Duesseldorf 1, FRG	Dipl-Ing Peter Stoller Head, Fluidized Bed Projects Dept	49-211-781-4458 8582729 VKW D	No	—	Yes	DBW	Sis	Wt	Bb[24]	20 to 1000	Up to 2650	Up to 1075	—[27]
Yalland Shipway Engineers Ltd[10] Pleasant, Wallsend ne & Wear NE28 6DR, UK	W E Chessum Sales Manager	44-705-381821 53611	No	—	No	—	—	Ft	Bb	5 to 60	150 to 250	Sat	—[1]
Aerotherm Engineering Inc 225 Mercimac St Woburn, Mass 01801	Dr Caren van Heppel Director, Market Development	1-617-938-9380 232-005 ASAS	No	—	Yes	UMI	JV	Wt	Bb[25]	20 to 200	Up to 2600	Up to 1000	—[1]
York Shipley Inc P O Box 349 York, Pa 17405	C Robert Lightner Manager, Alternative Energy Systems	1-717-755-1081 4761165 YRK SHP	No	—	No	—	—	Wt, Ft	Bb, Cr[10]	2 to 80	15 to 600	250 to 750	—[1]

9 -Typically saturated steam, though slight amounts of superheat are available
10 -A division of Combustion Engineering Inc. Focuses efforts on fluidized-bed boilers for oil-field use
11 -Combustion Systems Ltd is an organization responsible for licensing fluidized-bed boiler technology developed by the National Coal Board and British Petroleum International Ltd; it is not a manufacturer. Licensees building steam-generating equipment include Babcock Power Ltd, M E Boilers Ltd, Banks of Rotherham Ltd, Hitachi Zosen AA, Yoshimine Boiler Industry Co, Hyundai Heavy Industries Co Ltd, IAEC (Bombay) Ltd, and Stone Johnston Corp
12 -A division of Combustion Engineering Inc. Supplies fluidized-bed boilers for all markets except oil-field production. See listing for C-E Natco
13 -Agreement to co-market fluidized-bed boilers of the circulating-bed type
14 -Bubbling-bed boilers are built under a license from Fluidized Combustion Contractors Ltd, circulating-bed boilers under a license from Battelle Development Corp
15 -Fluidized Combustion Contractors Ltd, wholly owned by Babcock Power Ltd, concentrates on fluidized-bed-combustion technology development, providing a service to Babcock Power Ltd, its associated companies, and licensees. FCL no longer sells fluidized-bed boilers. That activity within the BPL organization is handled by BPL London and Birmingham and Babcock Worsley Ltd (see listings for those organizations.)
16 -Purchased the Fluidized-Bed Div of Energy Resources Co, listed in Powers last survey of fluidized-bed boiler manufacturers (August 1982, p S-8)
17 -Units feature recirculation of fines at rates as high as 15:1 (lb fines to lb fuel feed)
18 -Pyropower Corp, US, is a subsidiary; EVT Energie und Verfahrenstechnik GmbH, FRG, is a licensee; Hyundai Heavy Industries Co Ltd, Korea, Wagner-Bird AG, Austria, and Aalborg Shipyard Ltd, Denmark, are collaborating suppliers
19 -License is for bubbling-bed technology only
20 -Coal, woodwaste, biomass, and coal-washing wastes
21 -Licensees are Dawson & Mason Ltd, England, Toku-Kagyo Co Ltd, Japan, and Inbensa SA, Mexico
22 -Specifically, the ignited fluidized-bed combustion system
23 -In-bed circulation type
24 -Boilers can be designed for all fuels except biomass
25 -Formerly E Green & Son Ltd
26 -A subsidiary of Stone & Webster Inc
27 -Solids Circulation Systems Inc is a technology developer rather than a manufacturer of fluidized-bed boilers. Licensees of its technology are Foster Wheeler Boiler Corp, US, and Babcock Power Ltd, UK
28 -Formerly Johnston Boiler Co
29 -Bubbling-bed type
30 -In the US, contact W Cudnoh, Manager, Sulzer Brothers Inc, 200 Park Ave, New York, NY 10017, Tel 1-212-949-0999, TLX 127297
31 -Licenses fluidized-bed technology to Rauma-Repola Oy Wolarma
32 -Dual-bed type
33 -Also a circulating-bed system combined with a cyclonic combustor
34 -Data not updated since Powers last survey of fluidized-bed boiler manufacturers (August 1982, p S-8)
35 -Formerly Deborah Fluidized Combustion Ltd
36 -Units feature recirculation of fines at rates as high as 10:1 (lb fines to lb fuel feed)
37 -Units can be designed to fire all fuels listed in footnote 3 except some liquid wastes when burned alone

demolition of part of that unit's furnace and convection pass. Through the conversion effort, the utility expects to find a technical and cost-effective basis for responding to the acid-rain issue in the upper Midwest. In addition, NSP hopes to satisfactorily demonstrate its ability to achieve a higher unit capability and availability and to extend the life of an existing unit.

EPRI, which partially funded economic feasibility studies, has considerable interest in the project. It claims that more than 200 units, built between 1945 and 1965, with a total capacity in excess of 20,000 MW, are potential candidates for conversion to AFB combustion.

Foster Wheeler Energy Corp, supplier of the fluidized-bed system, began demolition work on Unit 2 last September under the direction of the utility and its architect/engineer, Stone & Webster Engineering Corp. When the refurbished boiler produces steam in the spring of 1986, it will be the largest AFB unit in the world. More important, Black Dog 2 will (1) be able to generate 40 MW more than it can now, (2) operate for 25 more years, (3) emit less pollutants, and (4) burn a wider range of fuels than currently possible. NSP's confidence in the $50-million project—or about $400/kW, one-third the price of new capacity—stems from the success of its fluidized-bed retrofit of the stoker-fired French Island plant, described in POWER's 1982 report referenced earlier.

Like other utilities, NSP has suffered from generating capability lost as a result of environmental regulations. The AFB retrofit will allow the 1954-vintage, 100-MW Unit 2, derated to 85 MW because of a mandated shift to a mixture of Illinois and low-sulfur western coals, to produce 125 MW while reducing SO_2

. . . TVA begins design of 160-MW plant

	PROJECT	COMBUSTION SYSTEM					EMISSIONS CONTROL						
		In-bed-surface erosion protection	Method of injecting fuel into combustion zone	Fuel-feed mechanism	No. of fuel-injection points	Method of controlling steam production	Type of dust collector	Internal recycle loop?	Particulate emissions at MCR[1], lb/million Btu	Sorbent $CaCO_3$ · $MgCO_3$ content, wt %	Calcium-to-sulfur mole ratio at MCR	SO_2 emissions at MCR[1], lb/million Btu	NO, emissions at MCR[1], lb/million Btu
1		Yes	Ov8	SSk	12	Vap[84]	MeC[53]	Yes	NAv	NAv	1.7:1	NAv	NAv
2		NAp	Ov8	NAv	NAv	—[23]	FFt	NAv	NAv	NAv	NAv	NAv	NAv
3		NAp	Ov8	CCv	2	Vol	MeC[53]	Yes[75]	0.083	NAp	NAp	NAv	NAv
4		NAp	Ov8	SSk	NAv	Vap[117]	FFt	Yes	NAv	NAv	NAv	NAv	NAv
5		NAp	Ov8	SSk	NAv	Vap[117]	FFt	Yes	NAv	NAv	NAv	NAv	NAv
6		NAp	Ov8	CCv	2	Vol	MeC[54]	Yes[76]	0.037	NAp	NAp	NAv	0.29
7		NAp	Ov8	CCv	2	Vol	MeC[54]	Yes[76]	0.083	NAp	NAp	NAv	NAv
8		NAp	Ov8	CCv	2	Vol	MeC[54]	Yes[76]	0.13	NAp	NAp	NAv	NAv
9		NAv	NAv	Pn	NAv	Vap[120]	MeC[78]	No	NAv	NAv	NAv	NAv	NAv
10		NAp	Ov8	SSk	4	Vol	Esp[80]	No	NAv	NAp	NAp	NAv	NAv
11		NAp	Ob	NAv	NAv	—[25]	FFt	NAv	NAv	NAv	NAv	NAv	NAv
12		N	UnB	Pn	72	Col	MeC[55]	No	0.03	39.6,8[145]	4.5:1	0.26	0.09
13		N	NAv	Pn	NAv	Col[29]	MeC[55]	Yes	NAv	NAp	NAp	NAv	NAv
14		NAp	Ov8	CCv	1	Vol	MeC[54]	Yes[76]	0.13	NAp	NAp	NAv	NAv
15		NAp	Ov8	CCv	1	Vol	Esp	Yes[76]	0.23	NAp	NAp	NAv	NAv
16		NAp	Ob	Scf	6	—[125]	FFt	Yes[126]	NAv	NAv[100]	2:1	NAv	NAv
17		N	Ob	Scf	4	Fol	MeC[54]	Yes[54]	NAv	NAp	NAp	NAv	NAv
18		NAp	Ov8	CCv	1	Vol	MeC[54]	Yes[76]	0.08	NAp	NAp	NAv	NAv
19		N	Ov8	SSk	3	—[26]	MeC[54]	No	NAv	NAp	NAp	NAv	NAv
20		NAp	Ob	RoV	2	—[25]	FFt	NAv	NAv	NAv	2:1	NAv	NAv
21		NAp	Ov8	CCv	1	Vol	MeC	Yes[76]	NAv	NAp	NAp	NAv	NAv
22		NAp	Ov8	CCv	1	Vol	MeC[54]	Yes[76]	0.083	NAp	NAp	NAv	NAv
23		N	Ov8[143]	SSk	2	Vap[84]	MeC[54]	Yes[76]	NAv	NAp	NAp	NAv	NAv
24		NAp	Ov8	NAv	NAv	NAv	FFt	Yes	NAv	90.2[147]	2.2:1[148]	NAv	<0.3
25		N	Ov8	SSk	3	—[25]	FFt[152]	No	NAv	NAp	NAp	NAv	NAv
26		NAp	Ov8	CCv	1	Vol	MeC	Yes[76]	1.49	NAp	NAp	NAv	NAv
27		B	Ov8	SSk	4	Col	MeC[54]	Yes[152]	0.077	39.6,8[145]	4:1	0.54	0.25
28		N	Ob	Pn	NAv	Vap[84]	FFt	Yes[152]	0.025	23.14[149]	2:1	0.045	0.05
29		NAp	Ob	DrT	6	Col[29]	FFt	No	NAv	NAp	NAp	NAv	NAv
30		NAp	Ob	NAv	NAv	—[25]	NAv	NAv	NAv	NAv	NAv	NAv	NAv
31		Clg	Ov8	SSk	4	Vap[120]	FFt	No	NAv	NAv	NAv	NAv	NAv
32		NAp	Ov8	WC	1	Vol	MeC	Yes[76]	0.44	NAp	NAp	NAv	0.32
33		B	Ov8	SSk	1	Vap[84]	FFt	Yes	NAv	NAv	NAv	NAv	NAv
34		Yes	Ov8	SSk	2	Vap[84]	FFt	Yes	0.03	94.1[149]	3:1	0.53	0.32
35		N	Ov8	DrT	2[90]	—[26]	MeC	No	NAv	NAp	NAp	NAv	NAv
36		Yes	Ov8	SSk	1	Vap[84]	MeC[54]	Yes	NAv	NAv[147]	2.5:1	NAv	NAv
37		B[28]	Ob	Pn	NAv	Vap[84]	FFt	Yes[76]	0.033	23.12[150]	1.7:1	0.05	0.033
38		Yes	Ov8	SSk	1[90]	Vap[84]	MeC[54]	Yes	NAv	99.6,0.1[149]	3:1	0.48	0.30
39		NAp	Ov8	RoF	4	Vap[120]	Esp	No	NAv	NAp	NAp	NAv	NAv
40		NAp	Ov8	SSk	2	Vol	Esp	NAv	NAv	NAp	NAp	NAv	NAv
41		NAp	Ov8	Pn[152]	1	Vol	MeC[54]	Yes[76]	0.083	NAp	NAp	NAv	NAv
42		NAp	Ob	NAv	NAv	—[25]	FFt	NAv	NAv	NAv	NAv	NAv	NAv
43		Yes[142]	Ob	Pn	18	Vol	FFt	No	NAv	95.3[155]	3:1[155]	NAv	NAv
44		N	Ov8	DrT	6	Vap[84]	MeC	No	NAv	NAp	NAp	NAv	NAv
45		N	Ov8	SSk	1	Vap[120]	FFt	Yes	NAv	NAv	NAv	NAv	NAv

and limestone crushing standard, reactivity, and particle size (note that the limestone used as a waste product).
Limestone is gravity-fed to the furnace via a chute

125 -Very rate of solids recirculation
126 -With recycle ratios of up to 7:1 (lb solids recycle below 800F to lb fuel feed)
127 -100% of sorbent less than 16 mesh. Injection into the furnace is directly into the bed at six locations via a screw feeder
128 -2.8 ft²; produces 40% of rated steaming capability
129 -51% of feed less than ¼ in., 22% less than 16 mesh
130 -775 ft² for steam generation; 366 ft² for superheat
131 -Also very number of coils in service, change bed temperature, and adjust fuel feed
132 -Coal is extruded into pellets ¾-in. diam × 6 in. long
133 -Units are ppm
134 -97 ft² for steam generation; 450 ft² for superheat
135 -Also from under the bed, using eight pneumatic injectors
136 -1184 ft² for steam generation; 4952 ft² for superheat; 861 ft² for reheat. In-bed surface produces 75% of rated steaming capability
137 -Including 102 ft² in reheater
138 -A total of 14 different coals will be tested in this unit
139 -Produces 25% of rated steaming capability
140 -100% over last 18 months
141 -30% of fuel less than ¼ in., 10% less than 16 mesh
142 -Also coatings
143 -Also very number of coils in service and fuel feed rate
144 -Including carbon burnup cell. In-bed surface produces 50% of rated steaming capability
145 -100% of sorbent less than ¼ in.
146 -Produces 30% of rated steaming capability
147 -100% of fuel less than ¼ in., 43% less than 16 mesh
148 -100% of sorbent less than ¼ in.
149 -Also plant washes, waste oil, and natural gas
150 -100% of fuel less than 16 mesh
151 -Also coffee husks and water-treatment sludge
152 -For coffee grounds; also conveyor for coal
153 -95% of fuel less than ¼ in., 14% less than 16 mesh
154 -100% of fuel less than ¼ in., 35% less than 16 mesh

SYMBOLS

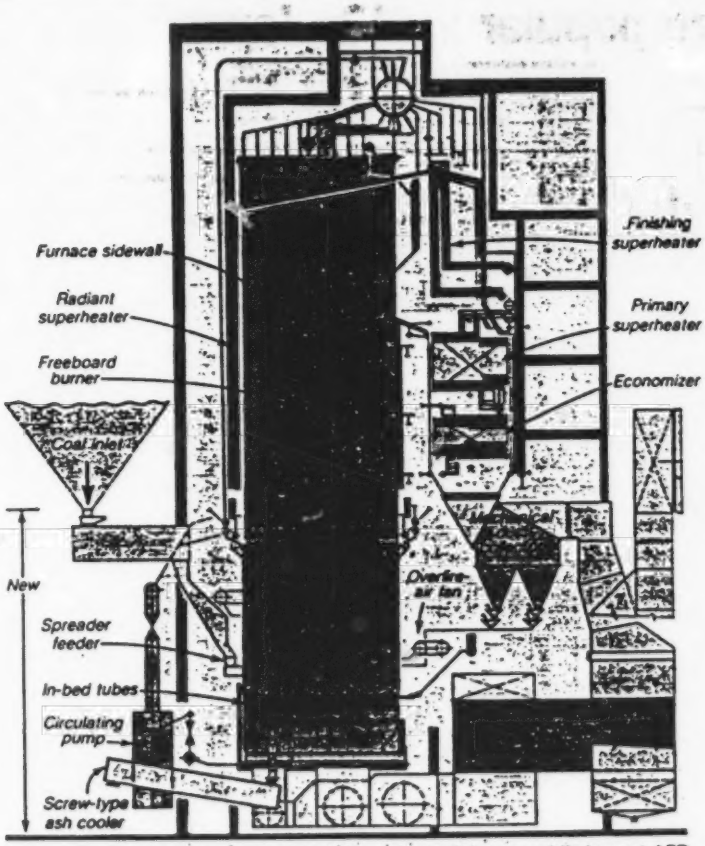
AlB -Alumina beads
Ant -Anthracite coal
Asp -Asphaltenes from heavy-oil upgrading
AsS -Asphalt-shingle waste
Bag -Bagasse
Bal -Balanced draft
Bb -Bubbling bed
Bc -Bubble caps
Bit -Bituminous coal
C -Coal
Cal -Very number of coils in service
CCv -Chain conveyor
CgF -Coal-feeder Bunch
CGr -Coffee grounds
Cir -Circulating bed
Com -Commercial
Ctg -Coatings
Col -Culm (anthracite mining wastes)
Dem -Demonstration
Dib -Directly into bed
DrT -Drop tube or chute
Esp -Electrostatic precipitator
Ext -Extruder
FbD -Fluidized bed dryer
FFt -Fabric filter
Fg -Flue gas
FB -Flow interrupters (studs, ball rockets, etc)
For -Forced circulation
Ft -Firetube
Ful -Fuel input
F/W -Firetube and watertube
G -Natural gas
Gob -Gob (bituminous mining wastes)
Gov -Government
HoA -Hot air
Hl -Half-loc nozzles
Hz -Horizontal
In -Inclined
Inr -Inerts from fuel
Inv -Change bed inventory
Is -Industrial sludge
Isd -Indirect steam dryer
Lig -Lignite
Lim -Limestone
Mba -Multiple beds with two or more compartments above distribution plate
Mbb -Multiple beds with two or more compartments below distribution plate
MeC -Mechanical collector
Ms -Municipal sludge
Msw -Municipal solid waste
N -None
NAp -Not applicable
NAv -Not available
Nat -Natural circulation
Noz -Nozzles
O -Fuel oil
OvB -From over the bed
Poo -Pool
Pet -Petroleum coke
P/G -Private and government
Pn -Pneumatic system
Pri -Private
Pro -Prototype
Prs -Press
Ret -Retrofit
RoF -Rotary feeder
RoV -Rotary valve
San -Sand
Sat -Saturated
Scf -Screw feeder
Sin -Single bed
Sp -Sparge pipes
Ssc -Single bed with separate startup cell
SSk -Spreader stroker
Stb -Stacked beds
Stn -Straight nipples on distribution plate
Sub -Subbituminous coal
T -Toe nozzles
Tg -Traveling grate
Ti -Tires (shredded)
Tuy -Tuyeres
Uc -Uncooled
UnB -From under the bed
Ve -Vertical
Vel -Adjust fluidizing air velocity
VC -Vibrating conveyor
Wc -Water cooled
Wo -Waste oil
Wt -Watertube
Ww -Woodwaste

emissions by up to 80%, cutting NO, emissions by up to 50%, and decreasing particulate discharges to 0.03 lb/million Btu—the last a provision of the current new-source performance standards. The turbine/generator and auxiliary systems must, of course, also be upgraded to achieve the higher unit rating.

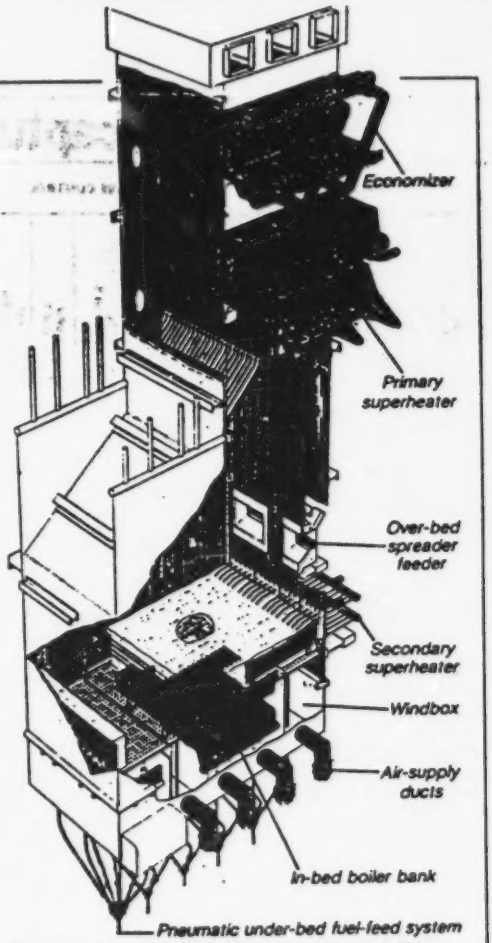
The original boiler for Unit 2 was designed to produce 860,000 lb/hr of 1770-psig/1000F steam; the re-equipped steam generator will deliver 1.04-million lb/hr at 1525 psig/1000F when firing the difficult Sarpy Creek (Mont) coal. This low-sulfur (0.9-1.2%), high-alkali fuel, noted for the fouling and slagging problems it causes, has been test-fired at French Island with favorable results. Tests to select the most cost-effective sorbent continue.

Design limitations of the existing boiler and NSP's desire to increase the unit rating created some job-specific requirements necessary to facilitate the conversion (Fig 2). These should be expected on any retrofit project of this type. At Black Dog they included:

- A maximum 10-ft/sec bed superficial velocity to minimize carryover of unburned coal and unreacted limestone. The limit essentially reduces the recycle rate to levels approaching those used on stoker-fired boilers. It was necessary to do this at Black Dog because of a 50-ft/sec maximum allowable gas velocity in the convection section at the maximum continuous rating (MCR) of the unit, and because of the need to restrict flue-gas particulate loadings to levels acceptable to existing precipitators with minimal upgrading.
- Addition of a multi-cyclone dust collector between the boiler outlet and air-heater inlet to allow recycle of high-carbon-content flyash and to reduce the dust loading at the precipitator inlet.
- Use of an over-bed (spreader stoker) coal and limestone feed system. Overfire-air ports will be located above coal-feeder inlets to the furnace to disperse the incoming coal fines from the feeder discharge area.
- Replacement of the two existing air heaters with a single, low-leakage regenerative unit capable of handling the higher pressure drops, flows, and particulate-loading requirements of the retrofit.
- Installation of new forced-draft fans and modifications to the existing induced-draft fans to satisfy the higher static-head and flow requirements of the AFB system.
- Use of a circumferential seal around the furnace to accommodate the differential thermal expansion where the existing furnace and the new fluidized-bed system are joined. The seal is a combination water/mechanical and slip-joint



2. Northern States Power Co's Black Dog plant will have world's largest AFB boiler when Unit 2 is converted from pulverized-coal firing in 1986



3. Success of this 20-MW pilot plant gave TVA confidence to begin design of a 160-MW unit

arrangement, with the furnace-gas-side pressure balanced at atmospheric at the seal elevation to minimize leakage.

- Provision for the injection of a flue-gas conditioning agent in case one is required later to facilitate dust collection by the precipitator.
- Reinforcement of existing boiler and precipitator gas-side pressure casings and of flue-gas and air ducts.

TVA: Another leader

The Tennessee Valley Authority took its first step toward a utility-scale demonstration of fluidized-bed technology by constructing a $68-million, 20-MW pilot plant at the utility's Shawnee steam plant in Paducah, Ky (Fig 3). The unit has operated for well over 8500 hours since the first coal fire in May 1982.

Encouraged by progress in the development of the AFB process over the last few years, TVA, in cooperation with EPRI, the state of Kentucky, Duke Power Co, Combustion Engineering Inc, and others, is designing a bubbling-bed boiler for Shawnee capable of providing sufficient steam to the existing Unit 10 turbine/generator to produce 160 MW. Completion of the $220-million project (a follow-on test and evaluation program are included in the cost) is expected in 1989.

Pilot-plant results indicate that 90% SO_2 retention is possible using under-bed fuel and limestone feed with a Ca:S ratio of 2.0 to 2.5 and a recycle ratio of 2.0 to 2.5 (lb solids recycled to lb new fuel added to the combustion chamber). Only eight years ago, the predicted Ca:S ratio was about 5 to achieve 90% SO_2 removal (without recycle). Results with over-bed feed—the TVA pilot plant has both under-bed and over-bed feed systems—show the same positive trends; however, overall boiler performance is not as good as when the under-bed feed system is used. When fuel is fed from over the bed, fines content must be tightly controlled to achieve the 97% combustion efficiency typically possible with under-bed injection.

Similar improvements in the control of NO_x emissions also have been observed. To illustrate: Data from Monongahela Power Co's 300,000-lb/hr Rivesville (WVa) demonstration unit (no longer operating) produced 0.6 lb NO_x/million Btu. The TVA pilot plant has operated at NO_x levels below environmental limits for all conditions tested and, at the expected 3% excess-O_2 operating level, emissions are less than 0.25 lb/million Btu.

Regarding equipment and component performance, the 20-MW-unit tests revealed the following:

- The relatively simple over-bed feed system operated at a high availability in approximately 1000 hours of testing. However, consistent fuel sizing was not possible and a special feed-preparation and -handling system would be necessary to control fines.
- Reliability of the original under-bed feed system was not satisfactory. Plugging caused by high moisture and large particles, and erosion of the feed pump and supply lines, were among the problems. Redesign of the system, use of wear-resistant materials, lower transport velocities, and other changes have since improved reliability considerably.
- Corrosion and erosion of in-bed tubes and tube supports have been within acceptable limits. Wear associated with the SA-210-A1 in-bed evaporator bun-

In-bed SO_2 capture popular in US, Japan

	PROJECT	COMBUSTION SYSTEM					EMISSIONS CONTROL						
		In-bed surface erosion protection	Method of injecting fuel into combustion zone	Fuel-feed mechanism	No. of fuel-injection points	Method of controlling steam production	Type of dust collector	Internal recycle loop[1]	Particulate emissions at MCR[2], lb/million Btu	Sorbent $CaCO_3$ $MgCO_3$ content, wt %	Calcium-to-sulfur mole ratio at MCR	SO_2 emissions at MCR[3], lb/million Btu	NO_x emissions at MCR[3], lb/million Btu
46		N	Dob	Pn	NAv	Vol[4]	FFt	Yes[5]	0.03	NAp	NAp	0.24	0.51[10]
47		N	OvB	SSt	NAv	Vol[4]	FFt	Yes[11]	0.04	NAv[14]	2:1	0.25	0.53[10]
48		N	Dob	Pn	18	Vol	FFt	No	NAv	55.0[108]	3:1	0.8	0.4
49		NAp	OvB	Pn	1	—[23]	MeC	No	NAv	NAp	NAp	NAv	NAv
50		NAp	OvB	SSt	2	Vol	Esp	No	NAv	NAp	NAp	NAv	NAv
51		Yes	OvB	SSt	2	Vol[10]	MeC[15]	Yes	NAv	93.9.1.4[40]	3:1	NAv	NAv
52		NAp	OvB	SSt	2	Vol	MeC	No	NAv	NAp	NAp	NAv	NAv
53		N	OvB	SSt	2	Inv[26]	MeC[16]	Yes	NAv	NAp	NAp	NAv	NAv
54		N	OvB	SSt	2	Vol[123]	FFt	Yes	NAv	NAv	NAv	NAv	NAv
55		Yes	OvB	SSt	1	Vol[4]	MeC[15]	Yes	NAv	94.1.3.[35]	3:1	0.5	0.5
56		N	OvB	SSt	2	Inv[26]	MeC[16]	Yes	NAv	NAp	NAp	NAv	NAv
57		NAp	OvB	SSt	2	Vol	Esp	No	NAv	NAp	NAp	NAv	NAv
58		N	Dob	Pn	18	Vol	FFt	No	NAv	99.0.3[130]	3:1[104]	NAv	NAv
59		NAp	Dob	DrT	1	Vol[4]	MeC[15]	Yes[125]	NAv	NAv	—[124]	0.02	0.1
60		N	OvB	SSt	2	Inv[26]	MeC[16]	Yes	NAv	NAp	NAp	NAv	NAv
61		N	OvB	SSt	2	Inv[26]	MeC[16]	NAv	NAv	NAp	NAp	NAv	NAv
62		NAp	UnB	Pn	8	—[23]	FFt	No	0.016	NAp	NAp	0.042	0.116
63		NAp	Dob	RoV	1	—[23]	FFt	NAv	NAv	NAv	NAv	NAv	NAv
64		NAp	NAv	NAv	1	—[23]	MeC	No	0.2	NAp	NAp	NAv	0.18
65		NAp	OvB	DrT	1	Vol	MeC	No	NAv	NAp	NAp	NAv	NAv
66		N	OvB[128]	SSt	NAv	Vol[4]	MeC[15]	Yes	NAv	NAv	NAv	NAv	NAv
67		NAp	OvB	SSt	2	Vol	Esp	NAv	NAv	NAp	NAp	NAv	NAv
68		Fl[102]	Dob	Scl	3	Vol[103]	MeC[15]	No	0.024	NAp	NAp	3.1	0.65
69		N	OvB	SSt	2	Inv[26]	MeC[16]	Yes	NAv	NAp	NAp	NAv	NAv
70		N	OvB	SSt	2	Col[29]	MeC	Yes	NAv	NAp	NAp	NAv	NAv
71		Yes	OvB	SSt	1	Vol[4]	MeC[15]	Yes	NAv	NAv[28]	3:1	NAv	NAv
72		NAp	OvB	SSt	2	Vol	Esp	No	NAv	NAp	NAp	NAv	NAv
73		NAp	Dob	Scl	1	—[23]	MeC	No	0.4	NAp	NAp	NAv	0.17
74		N	OvB	SSt	2	Inv[26]	MeC	Yes	NAv	NAp	NAp	NAv	NAv
75		Ctg	OvB	Rol	2	Vol[128]	FFt	No	NAv	NAv	NAv	50[128]	270[128]
76		Ctg	OvB	Scl	1	Vol[29]	FFt	No	NAv	NAp	NAp	NAv	NAv
77		N	OvB[28]	SSt[28]	1[28]	Vol	FFt	Yes[28]	NAv	90.1.5	2.5:1	NAv	NAv
78		NAp	OvB	DrT	1	Vol	MeC	No	NAv	NAp	NAp	NAv	NAv
79		NAp	OvB	Pn	1	Vol[112]	MeC	No	NAv	NAp	NAp	NAv	NAv
80		N	OvB	SSt	2	Inv[26]	MeC	Yes	NAv	NAp	NAp	NAv	NAv
81		N	OvB	Scl	1	Vol[29]	FFt	No	NAv	NAp	NAp	NAv	NAv
82		N	OvB[42]	DrT	1	Col	MeC[15]	Yes[42]	0.022	95.NAv[44]	2:1[35]	0.3	0.26
83		NAp	OvB	Pn	1	Vol[112]	MeC	No	NAv	NAp	NAp	NAv	NAv
84		N	OvB	Scl	1	Vol	MeC	No	NAv	NAp	NAp	NAv	NAv
85		NAp	OvB	Pn	1	Vol	MeC	No	0.4	NAp	NAp	NAv	NAv
86		Fl	OvB	Scl	1	Vol[113]	FFt	No	NAv	NAp	NAp	NAv	NAv
87		NAp	Dob	DrT	1	Vol[4]	MeC[15]	Yes	NAv	NAv	—[124]	NAv	NAv
88		N	OvB	Scl	1	Vol[113]	FFt	No	NAv	NAp	NAp	NAv	NAv

and limestone moisture content, reactivity, and particle size (note that the limestone used is a waste product); Limestone is gravity-fed to the furnace via a chute

125 -Very rate of solids recirculation

126 -Wide recycle ratios of up to 7:1 (lb solids recycle below 800F to lb fuel feed)

127 -100% of sorbent less than 16 mesh. Injection into the furnace is directly into the bed at six locations via a screw feeder

128 -2.8 ft^2; produces 40% of rated steaming capability

129 -51% of fuel less than ¼ in., 22% less than 16 mesh

130 -775 ft^2 for steam generation; 366 ft^2 for superheat

131 -Also vary number of coils in service, change bed temperature, and adjust fuel feed

132 -Gob is extruded into pellets ¾-in. diam × 6 in. long

133 -Units are ppm

134 -97 ft^2 for steam generation; 450 ft^2 for superheat

135 -Also from under the bed, using eight pneumatic injectors

136 -1184 ft^2 for steam generation; 4952 ft^2 for superheat; 861 ft^2 for reheat. In-bed surface produces 75% of rated steaming capability

137 -Including 102 ft^2 in reheater

138 -A total of 14 different coals will be tested in this unit

139 -Produces 25% of rated steaming capability

140 -100% over last 18 months

141 -30% of fuel less than ¼ in., 10% less than 16 mesh

142 -Also coatings

143 -Also vary number of coils in service and fuel feed rate

144 -Including carbon burnup cell. In-bed surface produces 50% of rated steaming capability

145 -100% of sorbent less than ¼ in.

146 -Produces 30% of rated steaming capability

147 -100% of fuel less than ¼ in., 43% less than 16 mesh

148 -100% of sorbent less than ¼ in.

149 -Also plant wastes, waste oil, and natural gas

150 -100% of fuel less than 16 mesh

151 -Also coffee husks and water-treatment sludge

152 -For coffee grounds; chain conveyor for coal

153 -95% of fuel less than ¼ in., 14% less than 16 mesh

154 -100% of fuel less than ¼ in., 35% less than 16 mesh

SYMBOLS

AlB -Alumina beads
Anl -Anthracite coal
Asp -Asphaltenes from heavy-oil upgrading
AsS -Asphalt-shingle waste
Bag -Bagasse
Bal -Balanced draft
Bb -Bubbling bed
Bc -Bubble caps
Bit -Bituminous coal
C -Coal
Cal -Vary number of cells in service
CCv -Chain conveyor
CgF -Coal-gasifier flyash
CGr -Coffee grounds
Cir -Circulating bed
Com -Commercial
Ctg -Coatings
Col -Colm (anthracite mining wastes)
Dem -Demonstration
Dib -Directly into bed
DrT -Drop tube or chute
Esp -Electrostatic precipitator
FFt -Fabric filter
Fg -Flue gas
FIt -Flow interrupters (studs, half moons, etc)
For -Forced circulation
Ft -Firetube
Ful -Fuel input
F/W -Firetube and watertube
G -Natural gas
Gob -Gob (bituminous mining wastes)
Gov -Government
HoA -Hot air
Hl -Hall-lee nozzles
Hz -Horizontal
In -Inclined[27]
Ine -Inerts from fuel
Inv -Change bed inventory
Is -Industrial sludge
Ind -Indirect steam dryer
Lig -Lignite
Lim -Limestone
Mbe -Multiple beds with two or more compartments above distribution plate
Mbb -Multiple beds with two or more compartments below distribution plate
MeC -Mechanical collector
Ms -Municipal sludge
Msw -Municipal solid waste
N -None
NAp -Not applicable
NAv -Not available
Nat -Natural circulation
Noz -Nozzles
O -Fuel oil
OvB -From over the bed
Pea -Peat
Pet -Petroleum coke
P/G -Private and government
Pn -Pneumatic system
Pri -Private
Pro -Prototype
Prs -Press
Ret -Retrofit
RoF -Rotary feeder
RoV -Rotary valve
San -Sand
Sat -Saturated
Scl -Screw feeder
Sin -Single bed
Sp -Sparge pipes
Snc -Single bed with separate startup cell
SSt -Spreader stroker
Stb -Stacked beds
Str -Straight nipples on distributor plate
Sub -Subbituminous coal
T -Tee nozzles
Tg -Traveling grate
Tr -Tires (shredded)
Twy -Tuyeres
Uc -Uncooled
UnB -From under the bed
Ve -Vertical
Vel -Adjust fluidizing air velocity
VsC -Vibrating conveyor
Wc -Water cooled
Wo -Waste oil
Wt -Watertube
Ww -Woodwaste

dle, SA-213 superheater tubes, and TR-304H tube supports are monitored at 500-hr intervals.

Plans for the 160-MW unit call for a balanced-draft, drum-type, bubbling-bed boiler to supply 1800-psig/1000F main steam to the existing high-pressure turbine and 450-psig/1000F reheat steam to the low-pressure turbine from the combustion of high-sulfur bituminous coal. An expansion joint in the freeboard section will allow a combination top- and bottom-supported unit, like Black Dog Unit 2. Fuel and sorbent feed will be from under the bed.

Bear in mind that an under-bed feed system is a virtual necessity for utility-size boilers designed with a single bubbling bed (an alternative could be the use of multiple stacked beds). Here's why: Over-bed feeders require a long, narrow furnace to ensure good fuel distribution from spreader stokers, which are limited in their throwing distance. Thus, the furnace for a 160-MW, single-bed unit would have to be about 70 × 36 ft in plan. A 500-MW unit would be half a football field in length or longer. Use of an under-bed feed system, by contrast, allows an evenly distributed flow of coal and limestone to a furnace of any dimension, so a more economical shape can be used.

The feed system being considered by TVA, jointly designed by Combustion Engineering and Power Recovery Systems Inc, is a modified version of what the now-defunct Energy Resources Co installed in Texas Tar Sands Ltd's bubbling-bed boiler. PRS purchased the fluidized-bed division of ERCO when it went bankrupt. The system, illustrated in Fig 4, uses a crusher/dryer to prepare the coal to these key specifications: ¼ in. × 0, less than 6% surface moisture. The second condition can be achieved comfortably as long as the surface moisture in the raw coal is 16% or less.

Prepared coal and limestone, stored separately, are fed from their respective silos through a system of pressure and gravimetric feeders and charging hoppers—where they are mixed—to 12 fuel distributors, so-called bottles. The enlarged view of a bottle in the illustration shows that it is a fluidized feeder with a central inlet and 10 2½-in.-diameter outlet fuel lines arranged concentrically around the inlet. The fuel-transport blowers pressurize the bottles to between 3.5 and 4 psig, enough to transport the coal/sorbent mixture to the furnace. The fluidizing velocity is 10 ft/sec. Designers say a bottle is analogous to a burner and that turndown of a fluidized-bed boiler using such a system is accomplished in the same way as load reduction on a pulverized-coal-fired unit.

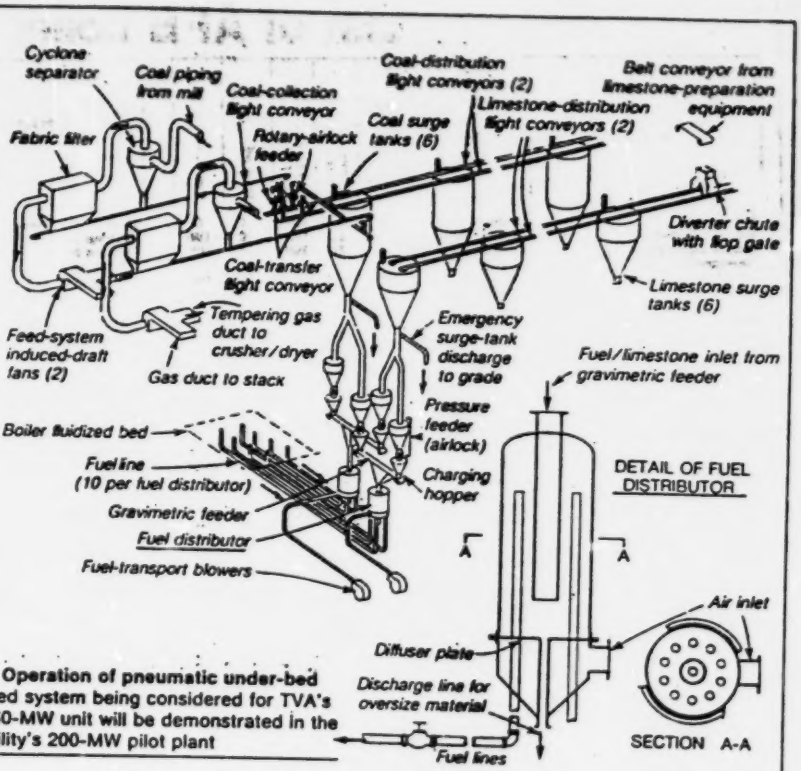
The TVA 160-MW unit would have

its bed divided into six firing zones each with two bottles, or 20 fuel lines, serving an area of about 400 ft². Plugging of feed lines caused by excessive surface moisture is not expected to be a problem. A rule of thumb that comes from pilot-plant experience says that you won't plug the feed system if coal flows freely from storage silos.

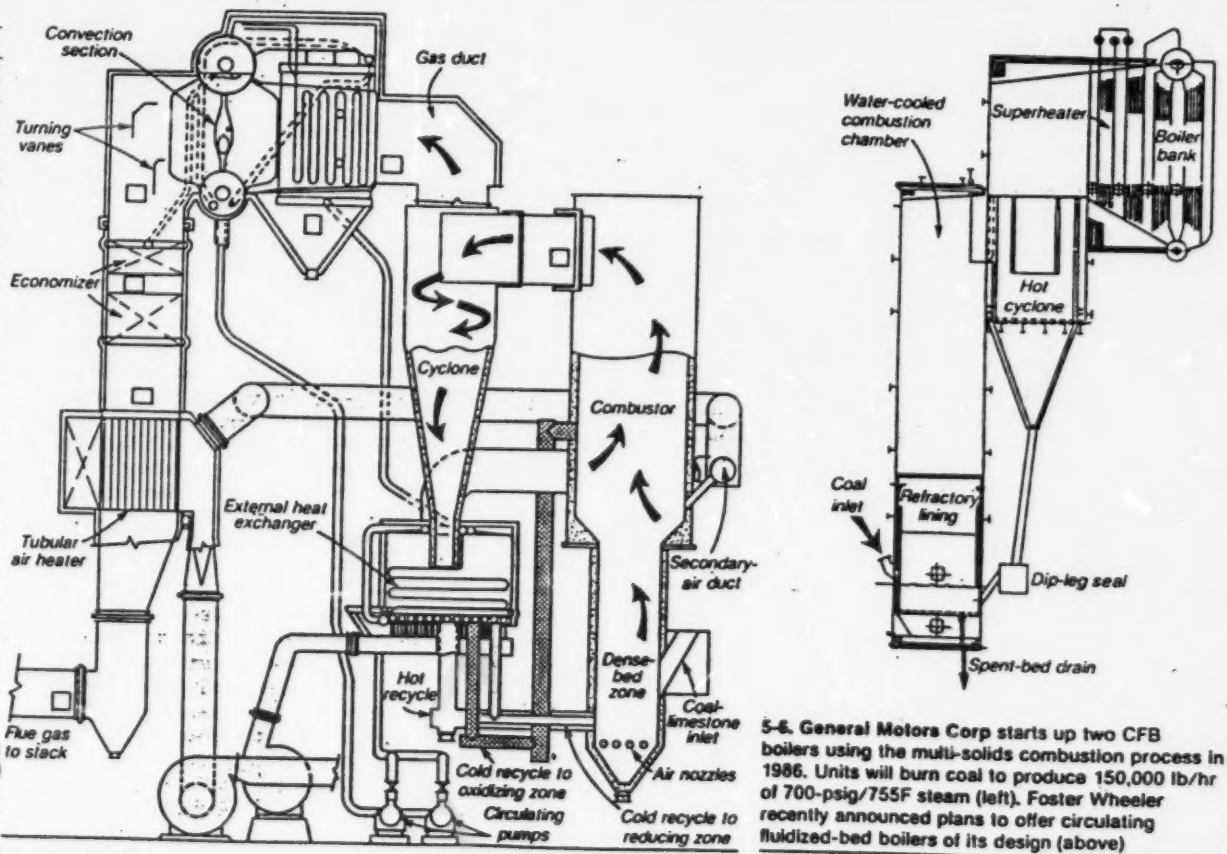
Overseas developments

The largest fluidized-bed boiler under construction outside the US reportedly is the CFB Lurgi GmbH is building for the West German city of Duisburg. When operation begins late this year, it will have the capability to produce up to 140 MW of district heat together with 70 MW of electric power and have the flexibility to generate up to 100 MW when no district heat is needed. In the optimum cogeneration mode, designers say, plant efficiency will exceed 90%.

Boiler for the reheat unit is sized to produce 595,000 lb/hr of 2100-psig/995F main steam. The water-cooled combustion chamber feeds hot solids via cyclone separators (arrangement of combustor and cyclones is similar to that at Nucla station) to two fluidized-bed heat



4. Operation of pneumatic under-bed feed system being considered for TVA's 160-MW unit will be demonstrated in the utility's 200-MW pilot plant



5-6. General Motors Corp starts up two CFB boilers using the multi-solids combustion process in 1986. Units will burn coal to produce 150,000 lb/hr of 700-psig/755F steam (left). Foster Wheeler recently announced plans to offer circulating fluidized-bed boilers of its design (above)

List of AFB boiler installations includes

PLANT OWNER	PLANT LOCATION	Commercial operation, year	Boiler capacity, 1000 lb/hr	Design fuel	Manufacturer
Scott Paper Co	Chester, Pa	86	650	C	CE
Stadtwerke Duisburg	Duisburg, FRG	85	594	C	LUR[1]
Atlas Consolidated Mining & Development Corp	Cebu, Philippines	82	352[2]	Lig	VKW
City of Flensburg	Flensburg, FRG	85	331	C	LUR
Ashland Petroleum Co	Catlettsburg, Ky	83	325[3]	PrC	FWC
Elektrizitaetswerk Westertal GmbH	Hamelin, FRG	83	308	C	VKW
Vereinigte Aluminiumwerke AG	Luenen, FRG	82	270	C	LUR
Oriental Chemical Co	Inchon, Korea	84	264	Pet,C	AHL
Sumitomo Joint Electric Power Co	Nehama East, Ehime, Japan	86	220	D	MIT
Metsaliiton Teollisuus Oy	Aanekoski, Finland	85	220	Wst[4]	AHL
New Brunswick Electric Power Commission	Chatham, N.B., Canada	Nkn	210	C	CE
A Ahlstrom Oy	Kauttua, Finland	81	200	C[5]	AHL
Ente Nazionale per l'Energia Elettrica	Porto Vesme, Italy	84	175	C	AMS
Papyrus AB	Kopparfors, Sweden	85	159	Wst[4]	AHL
Kemira Oy	Oulu, Finland	82	155	Pea,C	AHL
Zellstoff und Paper Fabrik AG	Frantschach, Austria	83	154	Lig[6]	AHL
Kemira Oy	Valkeakoski, Finland	82	143	C[5]	OUT
Hylte Bruks AB	Hylte Bruk, Sweden	82	143	Pea,C	AHL
Undisclosed	Austria	84	140	Sub	INT
Sumitomo Metal Industries Ltd	Kokura, Fukuoka, Japan	85	132[7]	C[10]	MIT
City of Uddevalla	Uddevall, Sweden	85	130	C[5]	GOT
City of Molndal	Molndal, Sweden	84	130	C[5]	GOT
City of Nyköping	Nyköping, Sweden	84	130[3]	C[5]	GOT
Mobel Chemotur	Karlskoga, Sweden	86	130[3]	C[5]	GOT
Sakido Salt Manufacturing Co Ltd	Sakido, Nagasaki, Japan	84	130	C	MIT
Rauma-Repola Oy	Rauma, Finland	84	128[8]	Ww,C	TAM
Ruhrkohle AG	Duesseldorf, FRG	79	110	C	VKW[9]
Technische Hochschule Aachen	Aachen, FRG	85	110	C	STM
Imatran Voima Oy	Lohia, Finland	85	108	C	VKW
Kemira Power Co	Kemira, Finland	85	102[10]	C	AHL
Mineracao Rio do Norte	Brazil	86	95	Ww	OUT
Nestle Co Ltd	Japan	83	95	Cg	IHI
City of Helsingborg	Helsingborg, Sweden	82	90	C	GOT
Sande Paper Mill A/S	Norway	85	85	RDF[5]	GOT
City of Ostersund	Ostersund, Sweden	85	85[10]	Wst[4]	AHL
Hyvinkään Lämpövoima Oy	Hyvinkää, Finland	81	85[10]	Pea,C	AHL
Oulunkumpu Oy	Kokkola, Finland	77	79	C[5]	OUT
Kemvamaki Oy	Lapuanjoki, Finland	81	79	Oil[5]	OUT
Ruhrkohle AG	Dortmund, FRG	81	73	Gob	DBW
City of Vaesterwik	Vaesterwik, Sweden	83	70	C[5]	GEN
City of Boden	Boden, Sweden	85	70	Pea[3]	GEN
City of Katrineholm	Katrineholm, Sweden	84	70	C,Ww	GEN
Mitsui Toatsu Chemical Co	Sasagawa, Japan	82	69	C	IHI
City of Avesta	Avesta, Sweden	83	65	C[5]	GOT
City of Sundsvall	Sundsvall, Sweden	84	65	RDF[5]	GOT
Undisclosed	Haifa Bay, Israel	82	60	Ch,PrW	EPI
Oulunkumpu Oy	Kokkola, Finland	77	56	C[5]	OUT
Kemvamaki Oy	Lapuanjoki, Finland	81	56	Oil[5]	OUT
Oy Alko AB	Koskenkorva, Finland	82	56	Pea	AHL
A Ahlstrom Oy	Varkaus, Finland	83	55	Ww	AHL
City of Sandviken	Sandviken, Sweden	83	51[3]	C[5]	GEN
Bord Na Mona	Ballyforan, Ireland	84	51	Pea	AHL
City of Aengelholm	Aengelholm, Sweden	84	50[3]	C[5]	GEN
Texas Tar Sands Ltd	Maverick County, Tex	82	50	Sub	PRS[10]
Undisclosed	Austria	84	50	Sub[4]	INT
Campbell Soup Co	Maxton, NC	82	50[11]	PrW,C	SJC
Stevenson Dyers Ltd	Ambergate, UK	82	50	C,PrW	FWP
Campbell Soup Co	Napoleon, Ohio	82	50[11]	C,PrW	SJC
Campbell Soup Co	Salisbury, Md	82	50	PrW,C	SJC
Boise Cascade Corp	Kenora, Ont., Canada	77	45	Ww,C	EPI
Chalmers University	Gothenburg, Sweden	83	44	C	GEN
A Ahlstrom Oy	Pihlava, Finland	79	44	Ww,Pea	AHL
House of Raeford Inc	Rose Hill, NC	82	43	Ww	YS
Griffin Industries Inc	Newberry, Ind	83	40	Gob	SJC
City of Linkoeping	Linkoeping, Sweden	85	40[3]	R[9]	GEN
Dalmond Steel Mill	Coeur d'Alene, Idaho	78	40	Ww	EPI
East Stroudsburg State College	East Stroudsburg, Pa	83	40	Ant	FEC[10]
Weyerhaeuser Co	Raymond, Wash	75	40	Ww	EPI
City of Vaesterwik	Vaesterwik, Sweden	84	35	C[5]	GEN
City of Bollnaes	Bollnaes, Sweden	83	35[3]	C[5]	GEN

MANUFACTURERS
- AHL -A Ahlstrom Oy (Finland)
- AMS -Ansaldo SpA (Italy)
- CE -Combustion Engineering Inc, in conjunction with Lurgi Corp
- DBW -Deutsche Babcock Werke AG (FRG)
- DED -Dedert Corp, Thermal Processes Div
- DFC -Deborah Fluidized Combustion Ltd (UK)
- DML -Davis of Netherton Ltd (UK)
- EPI -Energy Products of Idaho
- FEC -Fluidyne Engineering Corp
- FWC -Foster Wheeler Corp
- FWP -Foster Wheeler Power Products Ltd (UK)
- GEN -Generator Industri AB (Sweden)
- GOT -Götaverken Energy Systems AB (Sweden)
- GWL -Gibson Wells Ltd (UK)
- IHI -Ishikawajima-Harima Heavy Industries Co Ltd (Japan)
- INT -Integral Engineering Industrieinbedarf GesMBH (Austria)
- LUR -Lurgi GmbH (FRG)
- MIT -Mitsubishi Heavy Industries Ltd (Japan)
- NEI -NEI Cochran Ltd (UK)
- OUT -Oulunkumpu Engineering Oy (Finland)
- PRS -Power Recovery Systems Inc
- SJC -Stone Johnston Corp
- STM -L&C Steinmueller GmbH (FRG)
- SUL -Sulzer Brothers Ltd (Switz)
- TAM -Tampella Ltd (Finland)
- VKW -Vereinigte Kesselwerke AG (FRG)
- YS -York-Shipley Inc

SYMBOLS
- Ant -Anthracite coal
- C -Coal
- Cg -Coffee grounds
- Ch -Cotton hulls

exchangers arranged in parallel. These external heat exchangers (EHX) allow independent control of superheat and reheat temperatures. The dust collector is a hot electrostatic precipitator.

One advantage of having an external heat exchanger in a CFB is that it can easily compensate for variations in combustor heat absorption caused by changes in fuel properties and load conditions—that is, heat absorption in the EHX is increased when combustor absorption drops and vice versa. Thus, it is possible to maintain the optimum level of combustor performance at all times.

An EHX essentially is a refractory-lined box containing an air-distribution grid and an immersed tube bundle designed to cool hot solids delivered by the cyclone and then return them to the combustor. Fluidizing velocity is low (less than 3 ft/sec), solids density and heat-transfer coefficients very high. There is virtually no combustion in the EHX because the solids being recycled contain little carbon. Erosion/corrosion in the immersed tube bundle is not a consideration because of the low fluidizing velocity and the low level of combustion.

To compete against CFB systems, Deutsche Babcock AG (DB), West Germany's largest boiler manufacturer, is offering high-recycle-rate bubbling-bed systems in sizes up to 250 MW (electric rating), designed to meet the stringent new federal standards for SO_2 and NO_x control while economizing sorbent and achieving combustion efficiencies comparable to those offered by pulverized-coal firing. External recirculation rates range from 10 to 15 lb of solids recycle per lb of fuel added. DB engineers say the bubbling bed is less expensive to build and operate than CFBs for utility boilers of comparable size.

Such high recirculation rates, while improving SO_2 capture and carbon burnout, also cool the bed, reducing the amount of in-bed surface required to maintain the optimum temperature for SO_2 and NO_x control. Decreasing the amount of heat absorption in the bed was a DB design objective. The company has had its share of erosion problems, primarily in the Atlas Consolidated Mining & Development Corp units, located in the Philippines. Erosion there was corrected by replacing the original in-bed bundle with expensive square tubes (production tubes that in cross section resemble square bar stock with a hole drilled in the middle). These tubes are welded together, one over the other, in stacks of four.

Recent studies conducted by the manufacturer indicate that the most economical way to avoid erosion is to use refractory-covered waterwall sections as the in-bed heat-transfer surface. This way, the bubbling solids essentially impinge on only the refractory covering the lowest tube in the stack. Most of the heat released in the DB bubbling-bed steam generator is captured in the convective

these units . . . and 2200 more in China

PLANT OWNER	PLANT LOCATION	Commercial operation, year	Boiler capacity, 1000 lb/hr	Design fuel	Manufacturer
City of Landskrona	Landskrona, Sweden	83	253	RDF[7]	GER
City of Eksjö	Eksjö, Sweden	80	34	Ww	GER
Robinsons Ltd	UK	84	30	C,PrW	CWL
Götaverken Energy Systems AB	Gårdberg, Sweden	81	30	C	GDT
Sumter Plywood Corp	Livingston, Ala	78	25	Ww	YS
Atlantic Veneer Corp	Beaufort, NC	81	26	Ww	YS
Northwest Mississippi Jr College	Senatobia, Miss	80	27	Ww	EPI
Boise Cascade Corp	Emmett Idaho	77	25	Ww	EPI
Boise Cascade Corp	Moncur, NC	77	25	Ww	EPI
Webster Lumber Co	Bangor, Wis	77	26	Ww	EPI
Woolcombers Ltd	Bradford, UK	82	25	PrW,C	FWP
British American Tobacco Co	Souza Cruz, Brazil	81	25[10]	C	SJC
Abbott Laboratories	Casa Grande, Ariz	84	25	C	SJC
Diamond International Corp	Redmond, Ore	80	25	Ww	EPI
Kogap Manufacturing Co	Medford, Ore	79	24	Ww	EPI
Skelleftea Kraft AB	Skelleftea, Sweden	81	24[10]	Pea	AHL
Savon Voima Oy	Savonnyola, Finland	79	24[10]	Pea	AHL
Chapleau Lumber Co	Chapleau, Ont., Canada	77	23	Ww	YS
Nagel Lumber Co	Land O'Lakes, Wis	77	23	Ww	YS
Wade Wood Co	Wade, NC	79	23	Ww	YS
Danks of Netherton Ltd	Dudley, UK	NAv	20	C	DHL
Providence College	Providence, RI	84	20[9]	C	SJC
Superwood Corp	Phillips, Wis	77	20	Ww	EPI
Fleming Lumber Co	Crestview, Fla	81	20	Ww	SJC
IBM Corp	Charlotte, NC	80	20	C	SJC
Van Buren County Alcohol Inc	Bonaparte, Iowa	81	20	C	DED
Eastmont Forest Products	Ashland, Mont	74	20	Ww	EPI
Power Recovery Systems Inc	Cambridge, Mass	80	20	C	PRS
Kyungpuk Dyeing Co	Korea-	84	20	C	SJC
Merrell Brothers Lumber Co	Priest River, Idaho	76	20	Ww	EPI
HASTRA	Laumberg, FRG	83	19	C	VKW
City of Eksjö	Eksjö, Sweden	79	17	R	GEN
Danks Engineering Ltd	Oldbury, UK	81	16	C	DHL
City of Studsvik	Studsvik, Sweden	81	15	C[5]	GEN
Smith's Brewery Ltd	Tadcaster, UK	81	15	C	NEI

PLANT OWNER	PLANT LOCATION	Commercial operation, year	Boiler capacity, 1000 lb/hr	Design fuel	Manufacturer
H & B Lumber Co	Marion, NC	75	14	Ww	YS
Nowco Wood Products Inc	Cape Girardeau, Mo	78	12	Ww	YS
Overton Co	Sandy, NC	82	12	Ww	YS
Correctional facility	Hinsville, Ill	84	12[10]	C	SJC
Blue Triangle Hardwoods	Everett, Pa	84	11	Ww	YS
Rezai Corp	Higganum, Conn	79	10	Ww	YS
Atlantic Veneer Corp	Beaufort, NC	77	10	Ww	YS
Tenneco Ltd	Bristol, UK	80	10	Wfa	DHL
Boise Cascade Corp	Cascade, Idaho	80	10	Ww	EPI
Lindsay Olive Growers	Lindsay, Calif	76	10	PrW	EPI
Vermont State Hospital	Waterbury, Vt	77	10	Ww	EPI
Hayward Tyler Pump Co	Keighley, UK	80	10	C	SJC
Neste Lampo Oy	Mantsala, Finland	83	10[13]	C[12]	AHL
Alcohol distillation plant	Bardstown, Ky	81	10	C	SJC
US Dept of HUD	Norfolk, Va	82	10[13]	Tr,Ww	DFC[14]
McCallico Inc	Hughesville, Pa	78	8	Ww	YS
J A Olsen Co	Winona, Miss	78	7	Ww	YS
York Casket Co	York, Pa	83	7	Ww	YS
Iowa-Missouri Walnut Co	St. Joseph, Mo	75	7	Ww	YS
York Casket Co	York, Pa	77	7	Ww	YS
Tenneco Organics Ltd	Avonmouth, UK	80	6	Ww	DFC[14]
National Coal Board	Selby, UK	81	4[15]	C	NEI
North York County Council	Knaresborough, UK	82	4[15]	C	DFC[14]
Nelson Industries Inc	Fortville, Ind	81	3	C	SJC
Owen-Spencer School	Spencer, Ind	81	3[3]	C	SJC
Empresa Nacional Adaro de Investigacion de Minerias SA	Madrid, Spain	84	3[10]	C	DED
Kentucky Center for Energy Research	Lexington, KY	NAv	3[10]	C	DED
Undisclosed	Undisclosed	85	—[2]	C	SJL
Saarbergwerk AG	Voelklingen, FRG	82	—[2]	C	VKW
City of Parkanmaki	Parkanmaki, Finland	83	NAv	C[5]	OUT
City of Seinajoki	Seinajoki, Finland	82	NAv	C[5]	OUT
Frutos Tropicos	Brazil	84	NAv	Ww	OUT
Skelleftea Kraft AB	Sweden	85	NAv	C[5]	OUT
Companhia Brasileira de Metalurgia e Mineracao	Brazil	85	NAv	Ww	OUT
Mineracao Rio do Norte	Brazil	84	NAv	Ww	OUT

Gob -Gob (bituminous mining wastes)
Lig -Lignite
Pea -Peat
Pet -Petroleum coke
PrG -Process gases
PrW -Process wastes
R -Municipal refuse
RDF -Refuse-derived fuel
S -Sludge
Sub -Subbituminous coal
T -Tires (shredded)
Wa -Waste oils
Wd -Woodes
Wla -Waste bars
Ww -Woodwaste

FOOTNOTES
1 -In conjunction with Deutsche Babcock Werke AG
2 -Heats air for gas turbine in combined-cycle plant
3 -For each of two units
4 -Also woodwaste and sludge
5 -Also peat and woodwaste
6 -Also coal and peat
7 -Also coal and wood waste
8 -Also woodwaste
9 -Retrofit project
10 -Also blast-furnace gas
11 -For each of three units
12 -Also coal/water mixture
13 -Million Btu/hr (hot-water system)
14 -In conjunction with International Boiler Works Co
15 -In conjunction with C-E Natco
16 -Company recently sold; now known as Fluidized Combustion Ltd
17 -For each of four units

sections of the Benson boiler located above the combustion zone.

Impact on cogeneration

Except for annoying erosion problems in a few AFB boilers with in-bed heat-transfer surface, industrial fluidized-bed operating experience has been good, as indicated by the large number of new systems being installed. Predictions are that fluidized-bed steam generators will continue to capture a significant part of the industrial large-boiler market in the years ahead for two reasons:

First, the changing economics of cogeneration dictate increased use of low-grade fuels and industrial waste products for such projects to remain viable. AFB combustion systems are inherently capable of burning these low-cost sources of energy, as the tables show. Second, acid rain and other environmental issues mean even tighter controls on stack emissions in the future. The low combustion temperatures used in fluidized-bed boilers, and their ability to capture SO_2 during combustion, provides perhaps the most cost-effective control of NO_x and SO_2 discharges for industrial-size units.

Industrial CFBs

Circulating fluidized-bed boilers generally are considered more economical than bubbling-bed units for industrial applications requiring more than 150,000-200,000 lb/hr of steam. For large units, the taller furnace characteristic of the CFB boiler offers better space utilization, greater fuel-particle and sorbent residence time for efficient combustion and SO_2 capture, and easier application of staged-combustion techniques for NO_x control than bubbling-bed steam generators.

The most popular CFB designs among industrial users are the two described earlier: systems like Pyropower's at Nucla station that do not have an external heat exchanger and those like Lurgi's at Duisburg that do. To date, the largest CFB unit ordered by industry is the 650,000-lb/hr boiler bought by Scott Paper Co for its Chester (Pa) plant. A joint effort of Combustion Engineering and Lurgi, it will have an EHX.

Another manufacturer offering CFBs with external heat exchangers is Riley Stoker Corp, which operates under a license from Battelle Development Corp. The two boilers incorporating Battelle's multi-solid fluidized-bed combustion system recently sold to General Motors Corp differ from the CFB systems discussed thus far in that the lower part of the combustion chamber contains a dense bed of large particles of river rock which do not leave the combustor (Fig 5). Its role is to increase the residence time of the entrained bed of ash particles, fuel, and limestone in the combustor and to promote proper mixing of these constituents.

In the GM unit illustrated, note that the combustor has no heat-transfer sur-

face. Combustion temperature is controlled under normal conditions to 1650F ±50 deg F by the reinjection of relatively cool ash, fuel, and limestone via ports in both the oxidizing and reducing zones of the combustor. Recycle of hot solids is used to increase the residence time of difficult-to-burn fuels—such as petroleum coke—and to allow fast startup of the system.

Foster Wheeler's new CFB (Fig 6) incorporates design features that have worked well in the company's bubbling-bed units. These include:

- A water-cooled plenum and grid plate to eliminate problems resulting from grid-plate leakage and to allow quick startup by in-plenum burners.
- A hot-recycle cyclone specially engineered for rapid startup and minimum refractory maintenance.
- Membrane waterwall surface extending the full length of the combustor.

Unit shown, with a two-drum boiler bank, is for pressures up to about 900 psig; a single-drum design would be used for higher pressures. Unit sizes extend up to 700,000 lb/hr.

Bubbling-bed boilers

Bubbling-bed steam generators come in a variety of designs—including watertube, firetube, and combination watertube/firetube types; units with single or dual beds, both shallow and deep, etc. Sizes range from the smallest AFB boilers offered to the largest, as evidenced by TVA's commitment.

For capacities less than about 50,000 lb/hr, horizontal firetube designs generally are most economical, though vertical firetubes are appropriate for outputs below 10,000 lb/hr. Hybrid boilers, consisting of a watertube combustion chamber and firetube convection section, can extend the range of relatively low-cost construction up to about 90,000 lb/hr and increase the nominal 300-psig pressure limit on firetube boilers to 500 psig. Watertube AFB boilers generally are specified for outputs above about 50,000 lb/hr and for high pressures.

The price of bubbling-bed steam systems is dropping as experience builds and manufacturers can better predict performance and the cost of construction. In fact, you no longer have to pay a premium for the fuel flexibility and pollution control offered by AFB-boiler plants rated less than about 200,000 lb/hr. They can be had, from at least some manufacturers, for about the same price as an unscrubbed stoker-fired facility. Combustion-efficiency guarantees of 97-98% can be obtained when quality coals are burned.

Regarding absorption of SO_2, experience with good coals and practical limestones in bubbling-bed boilers indicates that about 80% retention is required to meet the commonly specified emissions standard of 1.2 lb SO_2/million Btu heat input. A rule of thumb is that a Ca:S ratio of 2 can achieve this level when operating in a steady-state condition with the bed temperature close to 1550F.

Limestone consumption at a Ca:S ratio of 2 is 6¼ lb/lb of sulfur in the coal. But, remember that because bed temperature and load are variable in most cases, the actual limestone supply must incorporate a moderate safety factor. Recycle, of course, improves sorbent utilization. The tabular material on pages S-8 and S-12 gives actual Ca:S ratios for key units. When reviewing this information, bear in mind that it was provided by the boiler manufacturer, not the user.

Availability data given on pages S-6 and S-10 indicate how fluidized-bed boilers are performing under actual industrial conditions. Unfortunately, most manufacturers completing POWER's questionnaires did not have access to the necessary plant data or the plants were not keeping this information.

The first seven months of operating experience for the 120,000-lb/hr single-cell bubbling-bed boiler installed at Midwest Solvents Co, Pekin, Ill, illustrate just how far the technology has come in a few short years. The first coal fire in the unit was ignited last May, only 16 months after contract award. Through the end of November, availability of the unit was 93.3% with no forced outages. Operators consistently have been able to turn down the boiler to 25% of rated load and regularly have increased steam output by as much as 20,000 lb/hr over a 30-sec period without more than a 15-20-psi drop in outlet pressure. These load changes have been accomplished with the unit in automatic control.

Erosion of in-bed tubes is an area of concern in the design and operation of bubbling-bed boilers. Though the literature (Refs 13, 14, 15) reveals wear problems, many boilers operate with negligible erosion. Encouraging news on industry's ability to deal with erosion comes from Central Soya Co, Marion, Ohio, where a 40,000-lb/hr firetube unit went into service in April 1980.

By the end of 1981, after 6300 hours of operation, sidewall wear of up to 0.080 in. was noticed; weld-buildup and a metal-spray treatment were prescribed. After 10,400 hours, 12 in-bed tubes had to be replaced with Schedule 80 pipe. Only 4000 hours later, operators found the original metal-spray coating worn away; a new coating was applied and wear fins made popular by the Chinese (POWER, March 1983, p 59) were welded to the tubes. After another 10,000 hours, the tubes and fins have exhibited only some minor metal loss. ■

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APPENDIX VI-2

NEW PRODUCT ANNOUNCEMENT

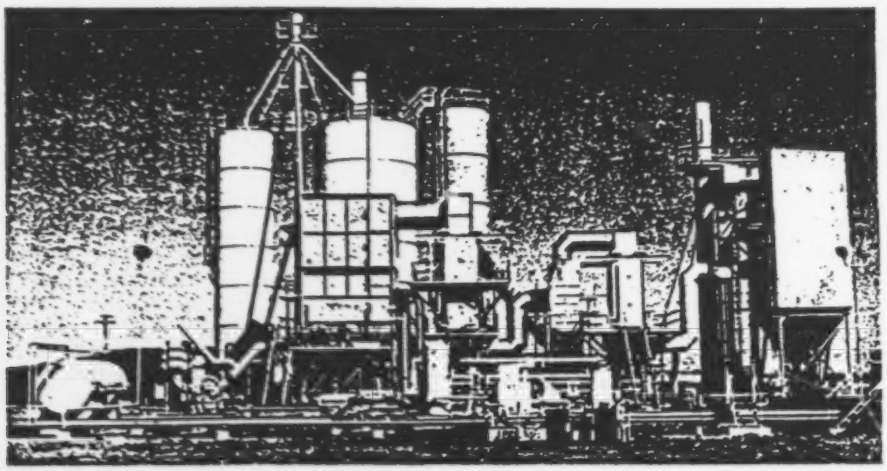
NATCO
COMBUSTION ENGINEERING, INC.

APPROVED FOR CUSTOMER REVIEW

FLUIDIZED BED COMBUSTION SYSTEM

C-E Natco has long been recognized as a leader in oil field steam generation technology. The THERMA DRIVE® steam generator has become an industry standard for once-through oil or gas fired generators. We have developed and introduced flue gas scrubbers, the LO-NOX burner, and a new subdewpoint convection section.

Our most recent contribution has been an atmospheric fluidized bed combustion (AFBC) steam generator, fired by coal rather than oil or gas. It delivers 80% quality steam, like THERMA DRIVE units, but offers much lower fuel costs for installation where coal is readily available.



Takes advantage of huge U.S. coal reserves

While fluidized bed combustion is not a new development, its application to oil field steam generation is new. It has become economically attractive because of the increased cost of oil/gas.

With the enormous coal reserves in the U.S., coal is available at relatively low cost. The development of coal fired steam generators offers some protection against oil embargoes or other real petroleum shortages. And when the price of oil/gas rises, coal fired generators become more viable.

First installation in tar sands oil recovery

C-E Natco's first AFBC steam generator is in operation in Maverick County, Texas operated by ENPEX, Inc. for Texas Tar Sands Limited. It is a skid-mounted 50 MM Btu/hr unit, includes all water treating and fuel handling systems and burns a locally available, high ash, low sulfur coal. In the initial phase, it is generating 80% quality steam at 2,450 psig for injection into one well. The project will produce 2° API oil from four wells.

How the AFBC Steam Generator Works

C-E Natco's atmospheric fluidized bed combustion (AFBC) coal-fired steam generator is a once-through design capable of generating 50,000 lbs/hr of 80% quality steam at a pressure of 2,500 psia. Sulfur oxides emission in stack gas is maintained within EPA stipulated limits by feeding limestone into the bed, thus eliminating the need for flue gas desulfurization. Limestone reacts with sulfur dioxide to form solid calcuim sulfate, which is easily disposed of with the bottoms and fly ash.

COAL FIRED AFBC STEAM GENERATOR

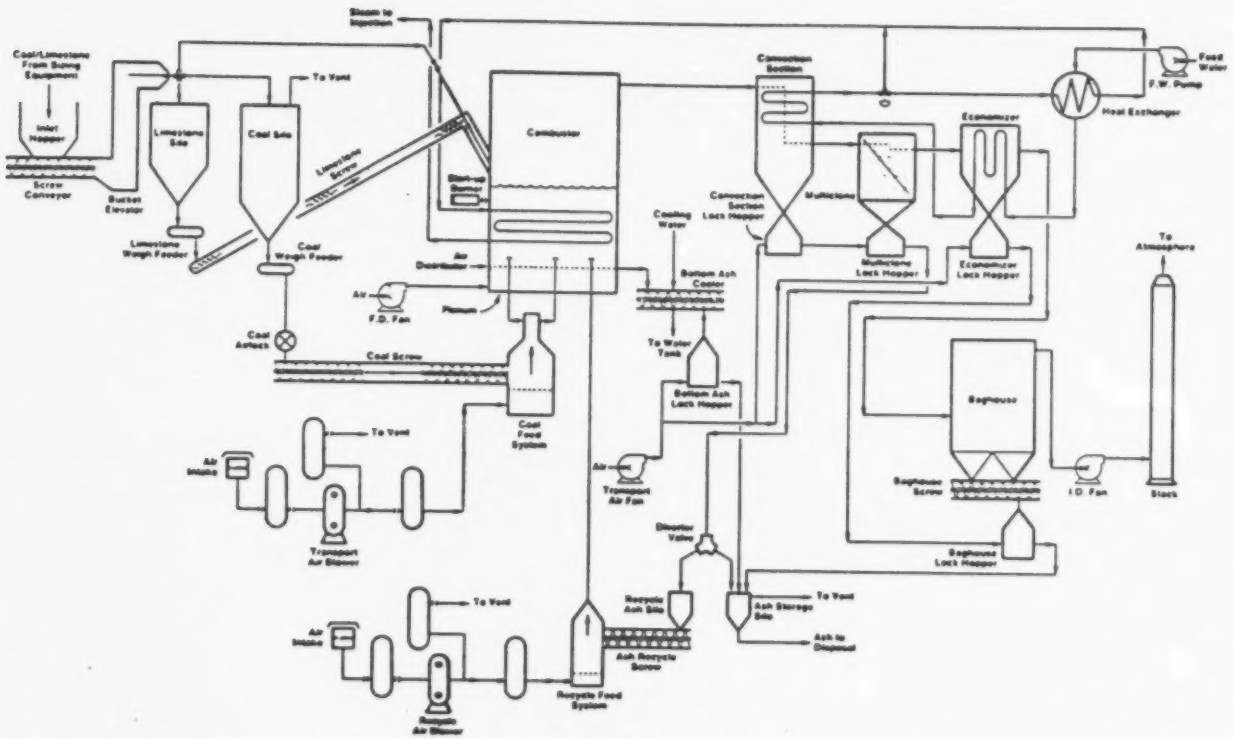
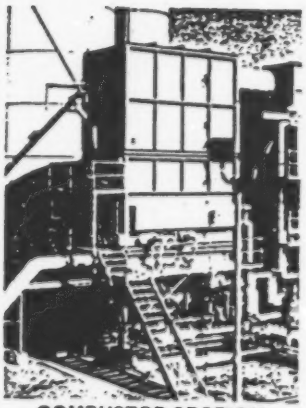


FIGURE 1



COMBUSTOR SECTION

The Combustor Section

Typically, 90% of the combustion reactions occur within the fluidized bed, which is approximately 5 feet deep and 130 square feet in area. (Refer to Figure 1.) Primary combustion air is supplied to the air plenum, located beneath the fluidized bed. The air flows up through hundreds of nozzles in the distributor plate, for even fluidization.

Temperature control and proper fluidization of the bed are critical to ensure good carbon burn-up, heat transfer and sulfur capture. Boiler tubes are mounted within the bed to maintain the bed temperature between 1,500 and 1,600 F. Since the bed is maintained at a relatively low temperature, the emission of NO_x in stack gas is well below the EPA allowable limits.

The remaining combustion reactions take place in the free board zone above the bed, where the temperature is maintained at 1,600 to 1,700 F to maximize carbon combustion and sulfur capture reactions.

Automated flow rates

Combustion air is supplied to the fluidized bed combustor by the forced draft fan, and transport air blower. The flow rates of air from these sources are added by the control system and maintained at a pre-set total for a selected coal rate. However, the air flow rate is also subject to a trimming signal dependent on flue gas oxygen content in order to automatically compensate for fluctuations in fuel quality. Limestone is supplied to the bed at a fixed ratio of limestone to coal, this ratio is predetermined by the requirements to control SO_2 emissions and to maintain bed depth. Combustor feedwater is treated as necessary and supplied at a fixed ratio of feedwater to coal feed rate, with the intention of maintaining constant 80% quality product steam.

With an optional fly ash reinjection system, fly ash caught in the mechanical dust collector and in the cinder trap under the convection section can be reinjected.

Coal and limestone feeding system

The coal and limestone are discharged from storage silos onto weigh-belt feeders, which supply the measured quantities of coal and limestone as required by the combustor.

A screw conveyor transports the coal from the weigh-belt feeder to an underbed pneumatic feed system. In this feed system the coal is entrained by transport air and injected into the bottom of the fluidized bed. Limestone is transported from the weigh-belt feeder via a screw conveyor and fed into the combustor, above the fluidized bed. The ash from the coal, plus reacted and unreacted limestone, is withdrawn from the bottom of the combustor to maintain the required bed height. Approximately 50% of the total generated ash is removed from the bottom of the combustor in bulk form via a water jacketed ash cooling screw. This bottom ash is pneumatically transported for storage in an ash silo.

Flue gas/heat exhange system

The combustion gases exit the fluidized bed combustor at a temperature of 1,600 to 1,700 F and at a pressure slightly less than atmospheric. An induced draft fan maintains a balanced draft in the freeboard section of the combustor. The hot gases, loaded with fly ash, enter the convective section where some heat is transferred to the feedwater. Part of the entrained fly ash is removed as it settles out of the combustion gas stream in a hopper at the bottom of the convective section.

The flue gases exit the convective section at approximately 750 F and enter a highly efficient multiclone. In the multiclone, entrained ash is removed at efficiencies in excess of 90%.

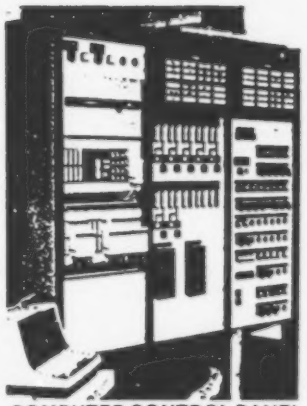
The collected solids are discharged pneumatically from the dust hopper at the bottom of the multiclone for recycle or disposal, depending on operation requirements.

The flue gas exiting the multiclone is then cooled from approximately 750 F to approximately 400 F as it passes through an economizer before entering the baghouse for final particulate removal. From the baghouse the flue gas enters the induced draft fan which discharges the flue gas directly into the stack.

Solids handling

Hot solids consisting mainly of ash and calcium sulfate from the bed are discharged into an indirect cooling screw mounted under the plenum area of the combustor. These solids are cooled to about 300 F in the cooling screw prior to being conveyed to an ash storage silo.

Ash from the baghouse and the three other collection points is transported pneumatically either to the ash storage silo or to the recycle ash silo from where it can be disposed of or recycled back to the combustor, depending on process requirements. The ash storage silo is equipped with an air filter system to allow transport air to exit but not the transported solids. Solids are discharged from this silo via a 60° cone equipped with a slide gate.



COMPUTER CONTROL PANEL

Computer automation

The C-E Natco AFBC steam generator is fully automated. A computerized control system supervises all critical functions and monitors variables in feed systems, bed temperatures, etc.

Construction

The steam generator itself is skid mounted for easy and low cost field erection. It is manufactured at the C-E Natco Tulsa plant, pre-assembled, for a check-out, then disassembled and shipped to the site. Relocation is feasible with this design.

Advantages

- Compared to a conventional 50.0 MM Btu/hr oil-fired steam generator, the coal-fired AFBC unit will save the user almost 50% on fuel cost.
- Compared to a conventional 50.0 MM Btu/hr gas-fired steam generator, the coal-fired AFBC unit will save the user about 40% on fuel costs.
- Compared to a conventional steam generator the lower combustion temperature (1,500 to 1,600 F) in the AFBC unit maintains NO_x emission levels well below the environmental requirements in most states.
- The AFBC unit in its present form is easily adaptable to congeneration applications.
- Utilization of limestone in the AFBC retains most of the sulfur in the solids exiting from the bed drain, eliminating the need for a flue gas desulfurizer.
- The main components of the unit are skid-mounted to facilitate transportation to and installation at the site.
- The overall control function is accomplished with a supervisory computer system which periodically monitors critical variables.

Research and Development

C-E Natco continues to investigate the application of fluidized bed combustion to oil field steam generatiion.

Parallel installations

The current designs for 50 MM Btu/hr could be boosted to 62.5 MM Btu/hr and remain skid-mounted. Larger plants could be built by installing two or more units in parallel and sharing solids storage and handling systems.

Alternate fuel

The AFBC steam generator burns coal, but can also burn lignite or petroleum coke.

For more information about the AFBC steam generator or other aspects of C-E Natco's steam generation technology, call:

- Suresh Sharma/Bruce Johnson • Tulsa Engineering

C-E Natco
P.O. Box 1710
Tulsa, Oklahoma 74101
918/663-9100

APPENDIX VI.3

PCR-116

OPERATING EXPERIENCE WITH CALIFORNIA'S FIRST COAL FIRED ENHANCED OIL RECOVERY STEAM GENERATOR

by
GILBERT B. WALDMAN, PYROPOWER CORPORATION
and HARRY OLLILA, PYROPOWER CORPORATION

PRESENTED AT:
COAL TECHNOLOGY '83
HOUSTON, TEXAS

NOVEMBER 16, 1983

"OPERATING EXPERIENCE WITH CALIFORNIA'S FIRST COAL FIRED ENHANCED OIL RECOVERY STEAM GENERATOR"

Introduction and Combustion System Description

Fluidized bed combustion is the only practical means of burning coal in environmentally sensitive areas, such as California, without the use of flue gas scrubbing for SO_2 control.

The PYROFLOW® circulating fluidized bed steam generation system provides a combustion process which utilizes limestone as an SO_2 sorbent. The limestone is fed into the combustion chamber where it combines with the SO_2 to form calcium sulphate and then discharged with other solid ash components. Low NO_x generation results from low combustion temperature (about 1550°F) and staged introduction of combustion air.

The PYROFLOW® fluidized bed combustion system (Figure 1) operates on the circulating bed concept, as distinct from conventional fluidized beds which have a fixed bed depth. The conventional fluidized bed must operate with air velocities that can only vary between the minimum and maximum fluidization velocities. At velocities beyond the maximum, the bed material becomes entrained, with carry-over of unburned particles from the combustion chamber. At velocities lower than the minimum, the bed or portions of the bed may slump.

With the circulating bed concept, the fuel, along with limestone for sulfur retention/control, is introduced into the combustion chamber. High air velocities used circulate the bed and fuel through the combustion chamber and into a cyclone collector that separates the hot gases from the solid bed and ash material. The latter are reinjected into the combustion chamber through a non-mechanical seal. Provisions are made for bottom ash separation and discharge. Hot flue gases pass through the cyclone collector and on to the convection zone of the boiler.

Some of the features of the PYROFLOW® circulating fluidized bed combustion system are:

1. High processing capability because of the high gas velocity per unit cross-sectional area.

2. The combustion chamber temperature is maintained at about 1550°F, which is ideal for the reaction between calcium and sulfur and minimizes the use of limestone throughout the load range of the steam generator.

3. Sulfur present in the fuel is retained in the form of calcium sulfate and discharged with the other ash solids. The use of limestone as a sorbent provides high sulfur retention within the combustion chamber, eliminating the need for any SO_2 scrubbing.

4. High combustion efficiency because of good lateral mixing fuel distribution, and increased residence time.

5. Better turndown and response rates than conventional fluidized bed combustors.

6. Elimination of unacceptable heat transfer surface erosion. All heat transfer surfaces in the combustion chamber are parallel to the flow of solids. This differs from conventional fluidized beds where combustion chamber heat transfer surfaces are generally perpendicular to the flow of solids.

7. The lower combustion temperature of the PYROFLOW® circulating fluidized bed combustion system has the advantage of eliminating the formation of molten slag and clinkers. The lower combustion temperature also greatly reduces the volatization of alkali salts which results in a reduction in the steam generator corrosion rates as well as limiting sootblowing requirements in the convection section of the steam generator.

8. Fuel with fines can be burned at high combustion efficiencies. Therefore screening of fines is not required.

The purchase of a PYROFLOW® unit was based upon a major oil company's evaluation of the design features of the system as applied to their enhanced oil recovery operation in Bakersfield, California. The steam generator, which is rated at 50 million BTU per hour output, produces 50,000 pounds of eighty percent quality steam at 2500 psig for underground heavy crude oil thermal recovery. Unit performance, as shown in Table 1 is based upon the coal and limestone analysis shown in Table 2.

TABLE 1
PERFORMANCE DATA

Maximum Continuous Output	50 MM BTU/HR
Steam Produced	50,000 LB/HR
Steam Quality	80%
Steam Pressure	2500 PSIG
Feedwater Inlet Temperature	70°F
Steam Generator Efficiency	82%

TABLE 2
COAL AND LIMESTONE DATA

Coal

Higher Heating Value	10,000 BTU/LB
Sulfur Content	0.6%
Proximate Analysis	(As Received)
Moisture	14.50%
Volatile Matter	35.15%
Fixed Carbon	36.85%
Ash	13.50%

Limestone

$CaCO_3$	90.3%
$MgCO_3$	1.04%
H_2O	.04%
Inert	8.26%

Mean Particle Size 150 micron

Steam and Water Flow

The steam side design of the unit is based on the existing once-through principles used in oil and gas-fired steam generators for enhanced oil recovery. The design incorporates two parallel water tubes in the steam generation section. As shown on the steam/water schematic (Figure 2) the incoming feed is routed through a regenerative preheater to the combustion chamber. The regenerative preheater is provided to prevent formation of condensate on the external surfaces of the economizer tubes. The two tubes follow an upward spiral path in the combustor and at the same time form the gas tight water wall enclosure for the combustion process. The tubes exit from the steam generator to deliver 80% quality steam to the steam separator. Steam is routed to the oil field steam distribution system from a single outlet.

Feedwater and steam velocities are high enough to ensure against internal waterwall tube deposits from the high concentration of solids in the feedwater. Use of the fluidized bed combustion of the fuel has the added advantages of a relatively low combustion temperature of 1550°F and provides uniform heat flux throughout the combustion chamber. This prevents localized heating of the tube surface and avoids tube burnout.

Coal, Limestone and Ash Handling

Three quarter inch coal is delivered from the coal crusher to a silo via a bucket elevator. Similarly, milled limestone is pneumatically transported to the limestone silo. Three day fuel and limestone storage capacity eliminates material handling requirements during long holiday weekends.

Coal discharges from the silo to a gravimetric feeder and is delivered to a single combustion feedpoint by a screw conveyor and rotary feeder. Air from the primary air fan is used to transport limestone to the combustor from a volumetric feeder at the hopper bottom.

Ash is removed from three points in the system. Bottom ash removal from the combustion chamber is by a water cooled screw conveyor which controls material inventory in the combustor. Flyash is collected from the economizer hopper and baghouse, and is carried, along with the bottom ash, to a fourteen day storage storage silo by a screw conveyor and ash elevator system.

System Operation

The start up and operation of the PYROFLOW® circulating fluidized bed boiler differs from traditional boilers only in the operation of the combustion portion of the system.

The primary FBC boiler components are the combustion chamber and the hot cyclone collector. Combustion and sulfur absorbtion take place in the combustion chamber, which is fully water-cooled with membrane walls. (Figure 3) Primary air is introduced through the bottom of the combustion chamber and the bed material-fuel mixture is fluidized. Secondary air is entered at two levels of the lower combustion chamber to ensure complete combustion. This staged combustion process also minimizes NO_x production.

The hot cyclone collector separates entrained particles from the flue gas stream. The collected particles are then gravity fed to a lower chamber, where they are combined with fuel and elutriated with high pressure air through a non-mechanical seal back to the combustion chamber. High-pressure air for fluidizing recirculated and new feed materials in the non-mechanical loop seal from the hot cyclone is supplied by a rotary positive displacement blower.

Flue gas leaving the cyclone collector continues to the convection zone. From the convection zone, the flue gas continues to a dust collection system, where the entrained particles are removed to meet environmental requirements. The flue gas is then discharged to the stack via an induced-draft fan.

The PYROFLOW® steam generator is equipped with a gas fired start up burner near the upper secondary air elevation. This burner is used to heat the bed to about 1000°F prior to feeding coal to the unit.

Coal is then fed at a minimum rate and bed heating continues. The start up burner is shut down when bed temperature reaches 1450°F, allowing the system to be operated solely on coal.

Load carrying gas lances are located near the bottom of the combustor. These lances start automatically when the bed temperature drops below a minimum setting and also provide back up capacity in the event of a coal feed interruption.

In the event of an emergency shutdown, fuel feed to the combustor stops immediately and the bed slumps into the refractory lined portion of the combustion chamber and heat transfer to the steam generating tubes stops.

SO_2 emissions are controlled by regulation of limestone feed to maintain a preset limestone to fuel feed ratio. A signal from the SO_2 analyzer is used to adjust the limestone feed rate to compensate for variations in coal sulfur content.

Operating History and Conclusions

<<Section 2>>

The PYROFLOW® unit was first fired on coal July 21, 1983. While a few months of operation can not be considered conclusive, the Bakersfield PYROFLOW® circulating fluidized bed steam generator is demonstrating its ability to provide a reliable source of steam for enhanced oil recovery. Actual operating problems have been minimal, and those which have occurred have involved plant auxilliary equipment rather than the steam generator itself. As of this writing, there have been no forced outages directly attributable to the steam generator. Feedwater pump difficulties have limited unit output to about eighty percent of rated capacity. The monthly availability of the unit since first coal firing in July has been August 85%, September 98%, October 98%. Table 3 shows the unit outages through mid-October.

TABLE 3
STEAM GENERATOR OUTAGES

Date	Event
7/26-/29	Repair broken coal screw feeder.
8/2-8/3	Feed pump repairs.
8/16	Plant power failure.
8/23-8/24	Repair broken coal screw feeder.
8/29	Boiler feed pump repairs.
9/11	Feed pump repairs.
9/21-9/22	Plant power failure.
10/7	Plant power failure.

The construction permit for this project from the Kern County Air Pollution Control District is based on the following maximum air pollutant emissions levels from the PYROFLOW® steam generator:

Oxides of Sulfur	5.5 lb/hr	41 ppm
Oxides of Nitrogen (as NO_2)	17.9 lb/hr	187 ppm
Carbon Monoxide	16.7 lb/hr	286 ppm
Particulate	3.3 lb/hr	0.019 gr/ACF

On September 1, 1983, emissions testing was performed by the Kern County authorities. The unofficial test results as presented in Table 4, show that the unit is capable of continuous operation with emissions levels below the allowable limits.

TABLE 4

Date	9/1/83	
Feedwater Flow	42,920 lb/hr	
Coal Feedrate	5,500 lb/hr	
Limestone Feedrate	250 lb/hr	
Combustor Bed Temp	1542°F	
Flue Gas O_2	3.9 %	
Baghouse Inlet Gas Temp	293°F	
SO_2 Emissions	2.4 lb/hr	20 ppm
Sulfur Retention	96.4%	
Calcium to Sulfur Ratio	2.19	
NO_X Emissions (As NO_2)	12.9 lb/hr	148 ppm
CO Emissions	0.10 lb/hr	2 ppm
Particulate Emissions	0.56 lb/hr	0.0037 gr/ACF

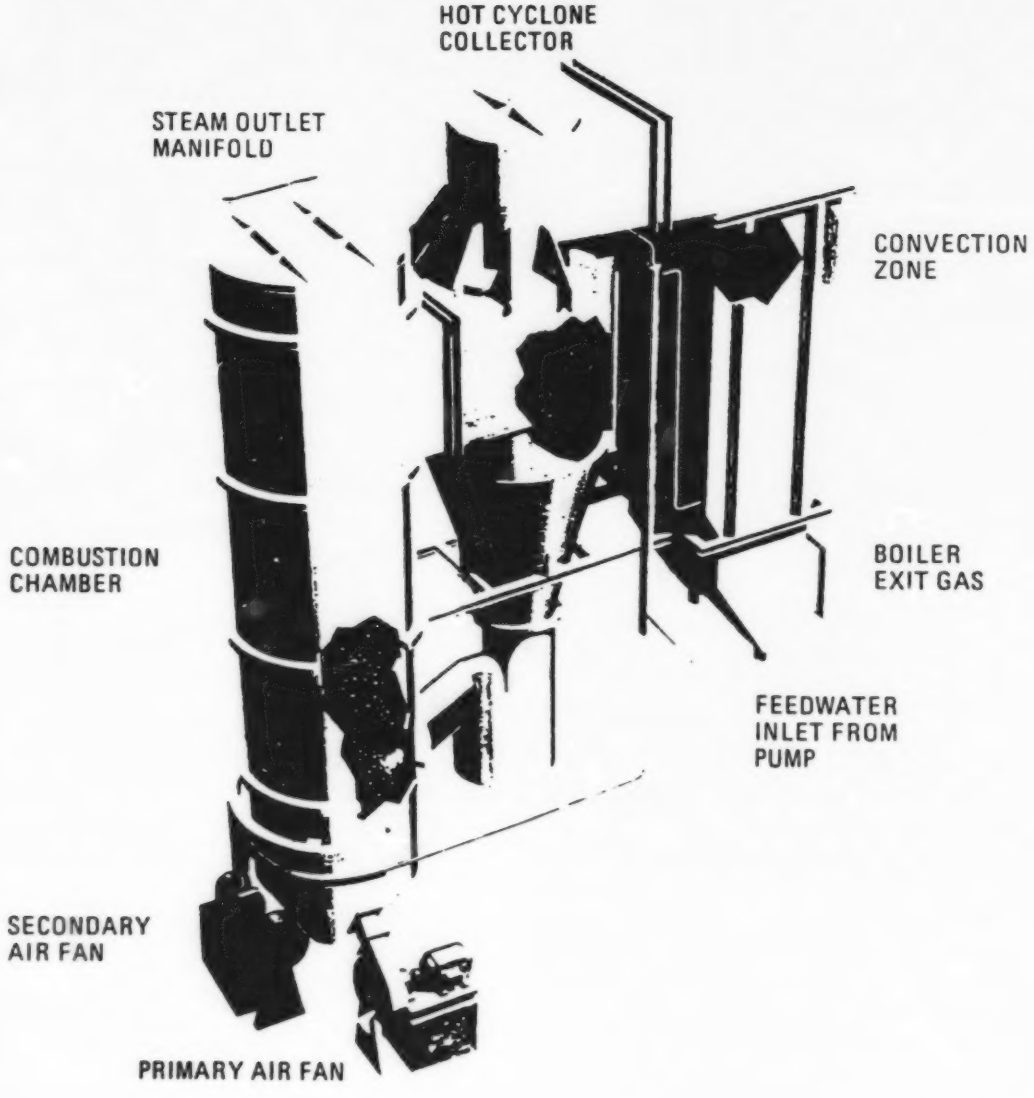


FIGURE 1. PYROFLOW CIRCULATING FLUIDIZED BED COMBUSTION SYSTEM

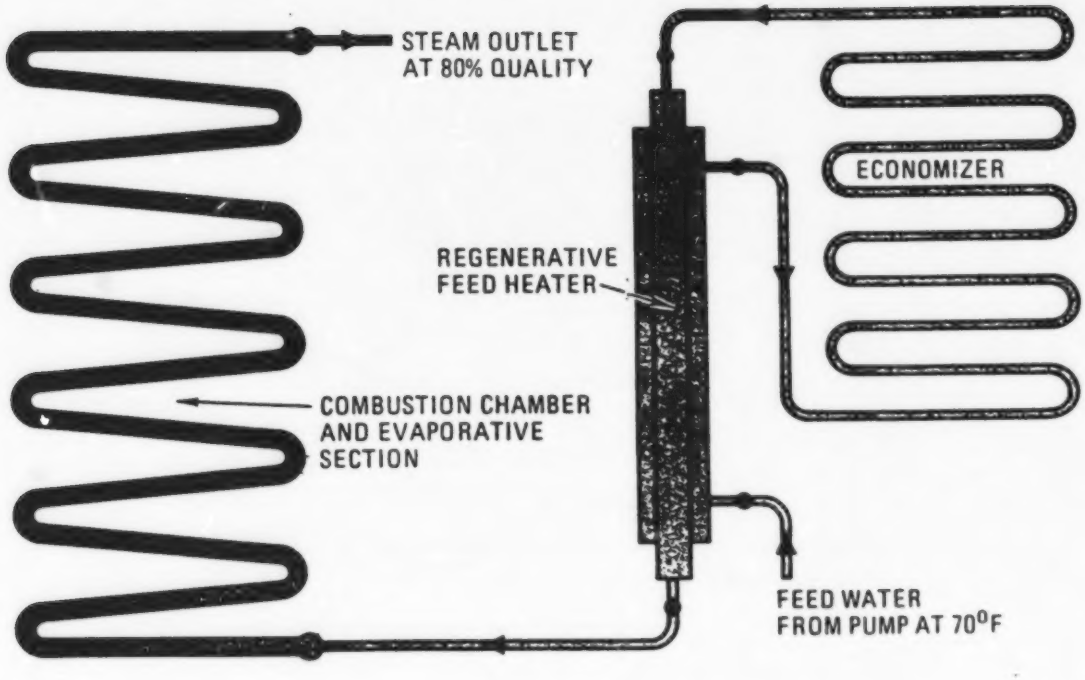


FIGURE 2. STEAM/WATER SCHEMATIC

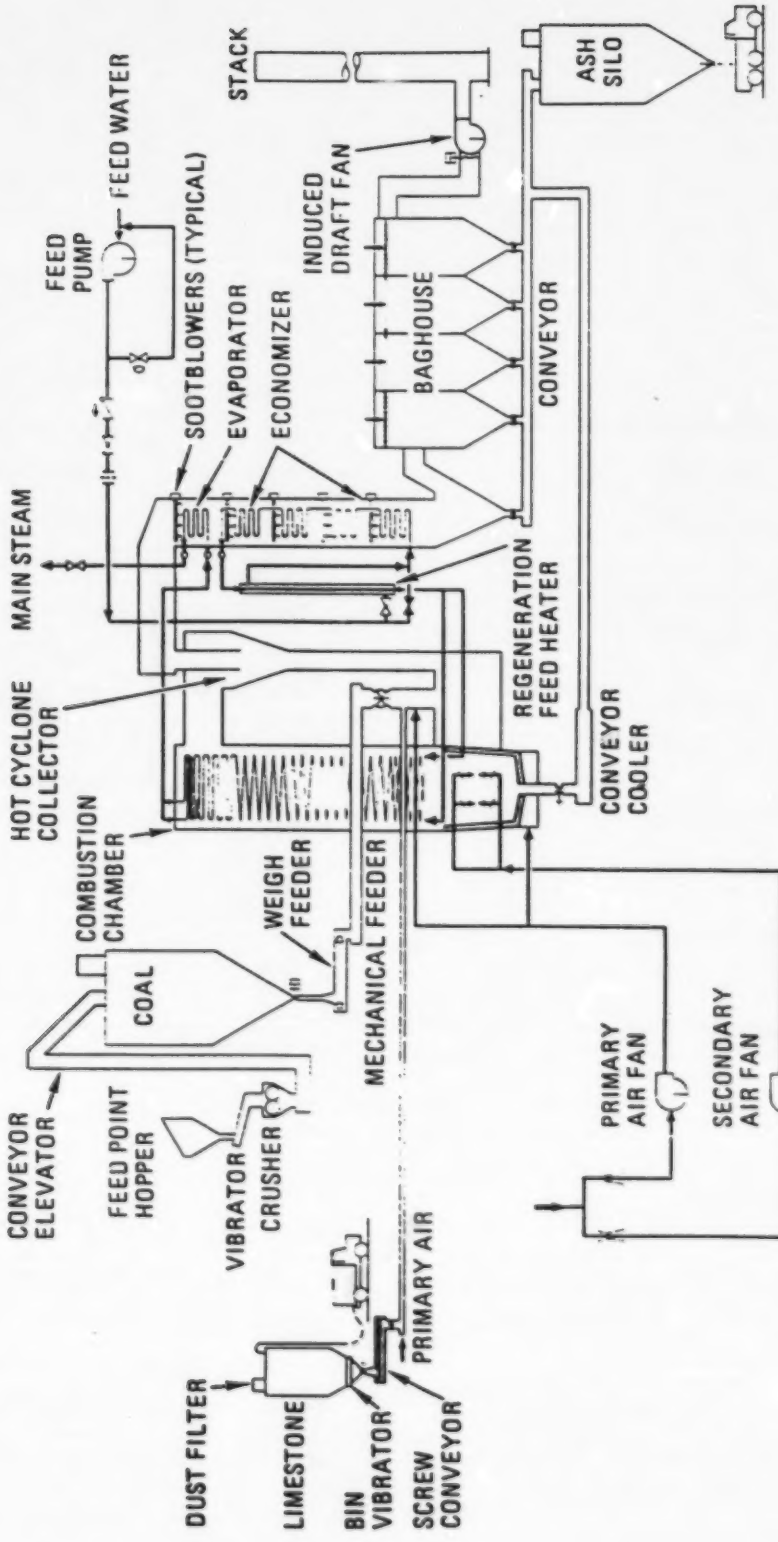


FIGURE 3. PYROFLOW® STEAM GENERATOR FLOW DIAGRAM